INTERNATIONAL
HELLENIC
UNIVERSITY

Power Plant Investment Decisions under Carbon Price Uncertainty

Minas D. Loulas

SID: 3302100027

SCHOOL OF SCIENCE & TECHNOLOGY

A thesis submitted for the degree of

Master of Science (MSc) in Energy Systems

OCTOBER, 2011

Power Plant Investment Decisions under Carbon Price Uncertainty

Minas D. Loulas

SID: 3302100027

Supervisor: **Dr. Katerina Sardi**

SCHOOL OF SCIENCE & TECHNOLOGY

A thesis submitted for the degree of

Master of Science (MSc) in Energy Systems

OCTOBER, 2011

DISCLAIMER

This dissertation is submitted in part candidacy for the degree of Master of Science in Energy Systems, from the School of Science and Technology of the International Hellenic University, Thessaloniki, Greece. The views expressed in the dissertation are those of the author entirely and no endorsement of these views is implied by the said University or its staff.

This work has not been submitted either in whole or in part, for any other degree at this or any other university.

Signed:...

Name: Minas D. Loulas

Date: 21/10/11

Table of Contents

List of Tables

List of Figures

Abbreviations

CDM	Clean Development Mechanism
CER	Certified Emission Reduction
EU ETS	European Union Emissions Trading Scheme
ETS	Emissions Trading Scheme
EU	European Union
EUA	European Union Allowance
EA	Emission Allowance
CET	Carbon Emission Trading
EC	European Commission
GHG	Greenhouse Gas
GBM	Geometric Brownian Motion
CCGT	Combined Cycle Gas Turbine
OCGT	Open Cycle Gas Turbine
IGCC	Integrated Gasification Combined Cycle and IGCC with pre investments
CCS	Carbon Capture and Storage
CAC	Command and Control
R&D	Research &Development
UNFCCC	United Nations Framework Convention on Climate Change
JI	Joint Implementation
NAP	National Allocation Plan
UN	United Nations
ESI	Electricity Supply Industry
ECX	European Climate Exchange
SRMC	Short Run Marginal Cost
LRMC	Long Run Marginal Cost
LDC	Load Duration Curve
SDC	Supply Demand Curve
LP	Linear Programming
LCOE	Levelized Cost of Electricity
ROV	Real Option Valuation

ROA	Real Option Approach
RES	Renewable Energy Sources
IRR	Internal Rate of Return
DCF	Discounted Cash Flow
NPV	Net Present Value

List of Equations

ABSTRACT

In a carbon constrained world, the right to pollute is a new factor which comes into play. Now that a price has been put on such emission allowances, power plant decision makers need to take this price into consideration in their calculations concerning short-term and long-term investment decisions.

Moreover, carbon price uncertainty due to various reasons, including climate policy has been often be accused of being one of the reasons why investments are postponed in power generation capacity in the EU. More specifically, the absence of long-term visibility and the volatility of the European carbon price have been strongly criticized by European utilities.

This thesis attempts to investigate the issue of carbon price uncertainty for European utilities and tries to evaluate its impact on the power sector finding reasons why utility corporate investors would delay their investments in generation capacity or would favor specific investment alternatives over others.

CHAPTER 1

INTRODUCTION

1.1 General Background

Tackling climate change depends on a complex system of decision making involving many different players with each one of those responding to a different set of incentives and risks while these interact which other. Furthermore these decisions are to be made at a global, national and corporate level Blyth, 2007 [1].

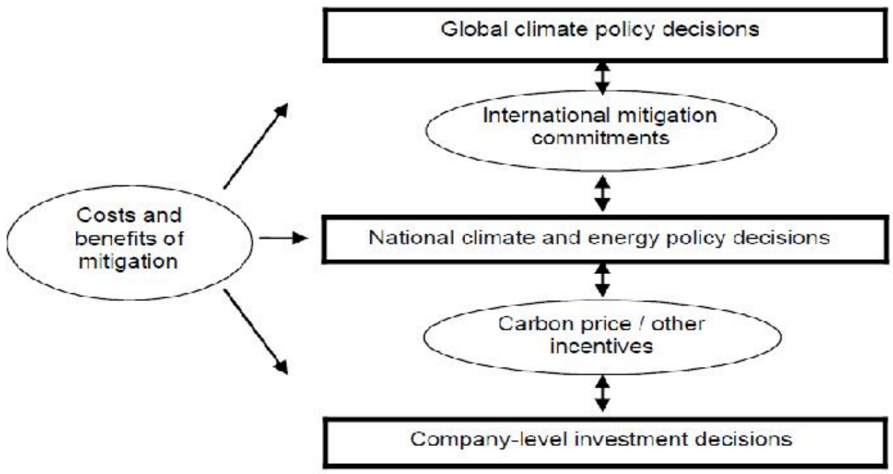

Figure 1.1: Decision-making involves interaction between different levels Blyth, 2007[1].

In an ideal world the costs and benefits of mitigation would be known, and reflected in international commitments within a global policy framework which allocates the necessary emission reductions to the national level. Emission reductions would then be delivered by companies responding to carbon price signals or other incentives and set at national or regional level to meet the agreed reductions.

In practice, decision-making within each of the three levels is often problematic with communication between the different levels of decision-makers being subject to uncertainty. Not only is there uncertainty about the costs and benefits of mitigation but these costs and benefits are significantly different for different countries. International negotiations lead to the fact that each country's commitment to action depends on other countries' commitments. Thus, investments in a company level will depend on expectations about the stringency of national regulation, while conversely the political will to set stringent targets will be more or less constrained by companies' willingness to act.

Already in 1997, governments within the UNFCC process signed the Kyoto protocol in order to take measures against climate change and reducing GHG emissions. Following that, the European Community has committed itself to decrease the CO_2 emissions with 8% by 2012 compared with the CO_2 emissions of 1990.

In order to push European Union member states to achieve their objectives in mitigating climate change, EU introduced a European wide emissions trading scheme (ETS) through a directive which was adopted in 2003 and it came into force at the beginning of 2005. The failures of recent global climate change negotiations (Copenhagen, Cancoun) and despite the implementation of a variety of climate policies around the world (IEA, 2009a [2]), it seems that we have reached a point where we can consider that the general agreement met in Kyoto may have been irreparably destroyed. The process is consistently being frustrated by a lack of engagement by many countries, but most importantly the US and China (world's two biggest economies).This reality combined with the looming, double-dip world economic recession (or depression?) in 2012 following the economic crisis of 2007, makes the startup plan to support the development of a global carbon market momentarily rather unrealizable.

In the absence of a clear global climate change policy framework, companies and especially energy intensive companies like power generators face uncertainty regarding the extent, timing and cost of any controls on emissions of greenhouse gases which in turn creates significant uncertainty about the companies' optimum investment strategy.

1.2 Power generation

Energy and particularly electricity is the basis for almost all economic activities nowadays, linked to growth and prosperity. According to IEA, [3] World Energy Outlook 2010 world electricity demand should grow on average by 2.2% per year between 2008 to 2035, from 17,000 TWh to 30,000 TWh. To ensure an adequate supply, the investment decisions of electricity generation companies are of great importance. Global generating capacities during the high growth phase in the 1960s and 1970s will have to be replaced and new capacities have to be installed, leading according to recent IEA studies to investments in about 5,000 GW of new generating capacities between 2000 and 2030 (Birol, 2003[4]).

Concerning the EU, substantial replacements in the power plant sector need to be realized (not only due to increasing demand but to over aging of the generation portfolio as well, for e.g., for Germany see Figure 1.2), which are expected to reach between 300 and 600 GW of installed capacity (Birol, 2003 [4]).

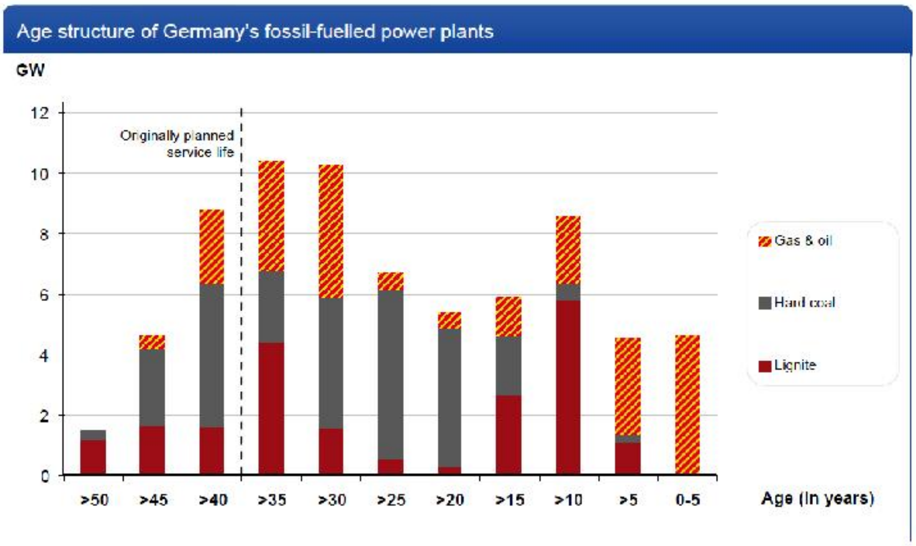

Figure 1.2: Germany's Generation Portfolio is Overaged: (>15 GW) Already Online Longer than Originally Scheduled (RWE, 2011[5])

Besides its importance for the whole economy, another important characteristic of the electrical power industry is its exposure to different kinds of uncertainty. In the past, the two main types of uncertainty have been the uncertainty about input costs (i.e. electricity and fossil fuel costs) and the uncertainty about future legislation.

Furthermore the environmental issue of electricity generation is of great importance with the electricity generation companies being among the biggest emitters of greenhouse gases emissions in industry. According to McKinsey & Company, 2009 [6] forecasts, until 2030 the global power sector will emit an estimated 18.7 gigatons of CO_2-eq and as the world has become increasingly focused on the need to reduce CO_2 emissions, the electricity sector has become a central strategy point. Even balancing emissions at the high-risk pathway of 550 ppm atmospheric CO_2 would require emissions to peak in the next 10 years (Stern, 2007[7]). Figure 1.3 shows the reductions required for different scenarios. Reaching the 550 level would require a cumulative reduction of 50 $GtCO_2e$ by the year 2050, a 60-65% decrease below business-as-usual.

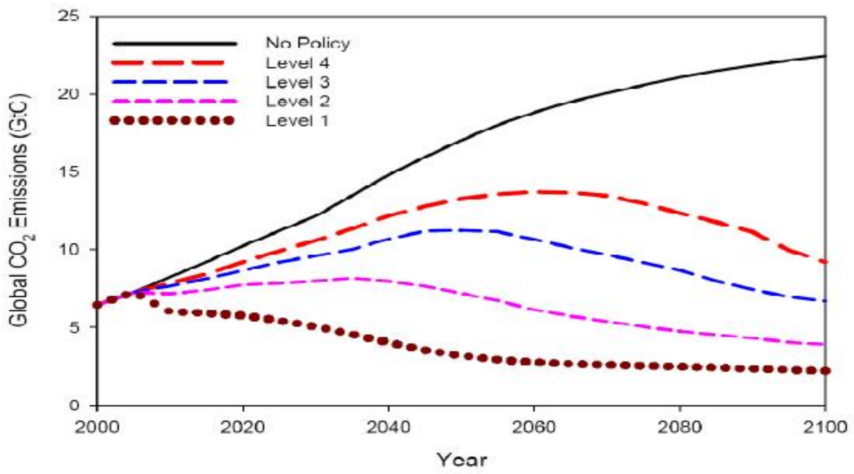

Figure 1.3: Stabilization Curves at different Atmospheric CO2 Concentrations (Stern, 2007[7]).

1.3 Power generation industry and emission reductions

The potential costs for abatement in the power sector at a global scale were calculated (McKinsey & Company, 2009[6]). Concluding that in the most optimistic scenario a reduction of 40-60% below 2005 levels by 2030 would cost as much as €55/t (Figure 1.4).

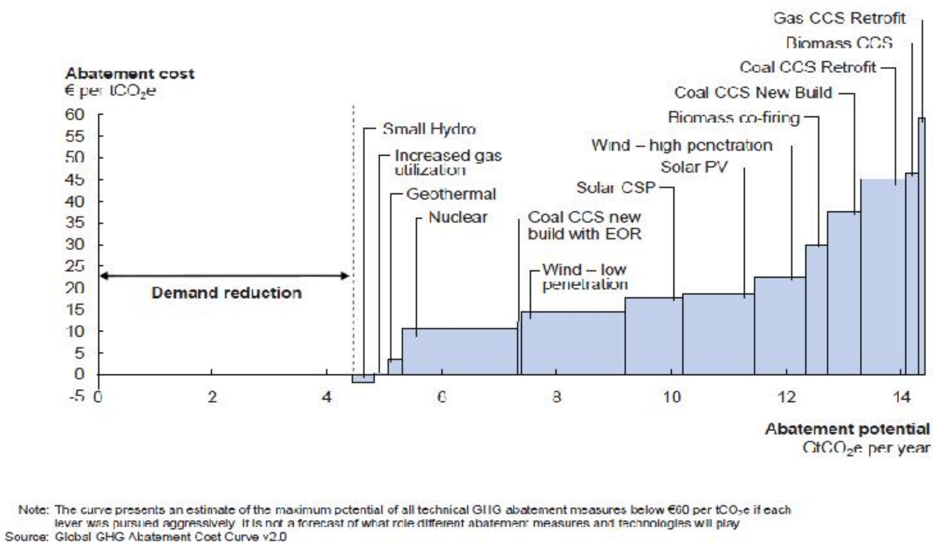

Figure 1.4: Global GHG Abatement Cost Curve for the Power Sector Societal Perspective 2030 (McKinsey & Company, 2009[6]).

As far as the capacity of the investment options are concerned, there is a total emissions reduction potential up to 14.4 $GtCO_2e$ per year in 2030 (McKinsey & Company, 2009[6]), although industry will face unprecedented challenges to adapt to the reality of climate change. Undoubtedly for the desirable targets to be accomplished, massive investments in carbon-free generation will be required. IEA, 2008[7] calculated that even if all power plants built from now onwards are carbon-free, emissions would only decrease 25% by 2020. Thus, in the coming years, both the demand for climate-friendly energy generation and the replacement of aging conventional generation facilities will lead to very large capital investments and planning efforts in the utility sector i.e. in Europe which is projected to invest over 2 trillion euro in adding and replacing power infrastructure in the next 20 years (IEA, 2008[7]) The future challenge for electricity utilities will be therefore to reduce their CO_2 emissions in the most economic and cost effective way.

1.4 Problem description

Even if part of the future investments will be done in renewable power plants, there will be definitely an additional need for new thermal power plants (coal, gas, lignite and possibly nuclear). These investments represent important strategic decisions for electric utilities since power plants require large investments. Furthermore, these investment decisions, especially concerning the choice of fuel and technology, although made by private corporations, have an impact on a number of public policy goals, including energy security and emissions of greenhouse gases.

The objective of the introduction of the EU ETS in Europe was to reduce emissions at minimum cost and also to provide an incentive for innovation (Hoffmann, 2007[8]).The cornerstone of this policy tool has been the imposition of a price on the emission of carbon dioxide with the intention that this price should cause an incentive for companies that are involved in emissions trading to reduce their CO_2 emissions.

One of the biggest problems that came to light for power utilities, alongside future energy prices uncertainty, was the uncertainty of the future CO_2 price since the demand for allowances and the cost and volume of the abatement technologies are hard to predict in advance and subjected to uncertainty besides the regulatory uncertainty of the EU ETS after 2012. The main concern is that it is uncertain how emissions trade will influence the profitability of an electricity company which is partly caused by the lack of knowledge on how the CO_2 price affects the profitability of an electricity company.

The price of CO_2 is taken into consideration in the short-term operations of a power plant because it increases the variable cost of daily power generation, while long term investment decisions of a power company are affected too by the carbon price uncertainty because they are followed by large capital outflows even before power plant commissioning, resulting in long payback periods . Such investments expose investors to long run uncertainties regarding variable costs, long-term future electricity prices, electricity demand, technology innovation risk and regulatory risk. Furthermore, these investments are characterized by irreversibility and while preserving for the decision makers the option to postpone investment, the competitiveness of nearly all electricity utilities depends on meaningful ways of valuing these huge investments. In this context, new power plant investment valuation methods including complicated models are developed and used nowadays by decision-makers.

1.5 Aim of this Thesis

This thesis focuses on the effects of uncertain carbon dioxide (CO_2) prices on investment decisions in the electricity generation industry. This work addresses the origins and the effects of this uncertainty concerning future emissions prices, on electricity generating firms' capacity investment decisions and shows the methodology used in coping with these effects.

It has to be pointed out that in the context of this work, although other carbon policies will be shortly discussed as well, the focus will be on power utilities which operate under the cap-and-trade CO_2 allowance scheme of the European Union (EU) called EU Emissions Trading Scheme (EU ETS) which is applied since 2005.

The outline of this thesis extends beyond the effects of carbon price uncertainty on power plant investment decisions to the investment valuation tools that are at the decision-makers disposal.

The rest of the thesis is organized as follows:

- Chapter 2 investigates the uncertainties which are related with power plant investments and which of those play the major role in power plant profitability and thus in investment decision making.
- Chapter 3 deals with different carbon policies, concentrating on the background of the cap-and-trade-scheme, on which the European EU-ETS is based , before, in the second half of the chapter, the short history and the experience collected in the six years of EU-ETS implementation, are discussed.

- Chapter 4 is dedicated, while including an extended literature review, on understanding the mechanisms which are in charge of forming the price of carbon which is the pillar of the EU ETS.

- Chapter 5 is an extensive review of the economic and operational effects that the carbon price imposes on power plants, including its effect on electricity prices and short term abatement procedures.

- Chapter 6 presents modeling approaches (including literature reviews) of future energy prices whose everyday volatility is the biggest threat for power plant profitability and investment decision making.

- In Chapter 7 various investment methodologies and valuation methods are described and compared, from the more simplistic to more complex and an extended literature review on how the carbon price uncertainty influences investment decisions is included as well.

- Chapter 8 brings in the conclusions of the thesis.

CHAPTER 2

UNCERTAINTIES RELATED TO POWER PLANT INVESTMENTS

2.1 Introduction

Uncertainty is almost everywhere in energy related decision making. It has many sources, numerous aspects and multiple implications. From the uncertainties surrounding global warming over the insecurity of future technological progress to the volatility of fuel and other energy prices, the uncertainties account for an important part of the current energy strategy puzzle. This is the reason why, despite the fact that the standard analysis of investment choices in electricity generation uses a cost-minimizing approach, investors do not choose to build new power stations solely on the basis of their expected costs because sustained additional risk raises the cost of capital, and will alter investment decisions. Companies wish to make profits, and simultaneously to avoid excessive risks, hence they balance between the appropriate mix between risk and return.

Next we will discuss generally about sources of uncertainty to power plant investments while afterwards we will focus on the uncertainties which affect the company's return of investment.

2.2 Sources of uncertainty and implications for power generation investment

Energy investments are exposed to different types and degrees of risk, with consequences for the cost and investment of capital. The higher the risk associated with an investment, the higher the cost of capital and the higher the return of capital required by investors. The amount of risk involved in any energy project and its significance vary depending on the scope of the project: planning, construction, start-up, and operation.

Risks occur not only from the project itself, but also from changes in the country and international investment environment, such as economic and political conditions and energy policies. More specifically, power plant investments are exposed to uncertainties and a range of risks based on relatively long time planning which must be considered when deciding on power plant investments and the high volatility of fuel prices which provoke sudden price fluctuations while having an important influence on generation costs. Furthermore, additional risks were created by the introduction of competition in wholesale and retail markets due to the liberalization of the electricity markets and by the introduction of emissions controls regulations. Table [1] shows energy sector risks which was proposed by IEA.

Table 2.1: Risks facing Energy sector investments, source: International Energy Agency, World Energy Investment Outlook (Paris: IEA, 2003[9]).

Economic risk	Market risk	• Inadequate price and/or demand to cover investment and production costs • Increase in input cost
	Construction risk	• Cost overruns • Project completion delays
	Operation risk	• Insufficient reserves • Unsatisfactory plant performance • Lack of capacity of operating entities • Cost of environmental degradation
	Macroeconomic risk	• Abrupt depreciation or appreciation of exchange rates • Changes in inflation and interest rates
Political risk	Regulatory risk	• Changes in price controls and environmental obligations • Cumbersome administrative procedures
	Transfer-of-profit risk	• Foreign exchange convertibility • Restrictions on transferring funds
	Expropriation or nationalization risk	• Changing title of ownership of the assets
Legal risk	Documentation or contract risk	• Terms and validity of contracts, such as purchase/supply, credit facilities, lending agreements and security/collateral agreements
	Jurisdictional risk	• Choice of jurisdiction • Enforcement risk • Lack of a dispute-settlement mechanism
Force majeure risk		• Natural disaster • Civil unrest • Strikes

In a wider context there are four types of risks associated with energy investment: economic, political, legal and force majeure risk. Moreover, Lemming [10] chooses a simple way to describe risk by categorization based only on its effect on cost, price and volume because financial returns are the key parameters for corporate risk management in electricity markets.

According to literature the most fundamental risk for power generation companies, particularly in competitive market conditions, is electricity price risk which is the major driver for power plant investment profitability above fuel price and carbon price. As the different risks are highly interrelated, it is important that this relationship is captured by a method used to determine future contribution margins for new units and determine power plant investments interconnected with profitability. This will be discussed in chapter 7.

2.3 Main Investment decisions drivers: Risk minimization and profitability

Any investor is interested in the cost-benefit of his investment, therefore an estimation of the expected investment profitability is indispensable. Roques *et al.* (2006a)[11] show that a probabilistic valuation model of investment is needed to give the full picture of the expected return on an investment and its distribution.

Considering primary short-term investment decisions for existing power plants the operational decisions of power companies are driven by the objective to maximize profitability. Furthermore, due to the fact that different types of power plants serve different load levels, the operational decisions which have to be made by the operators on a short-term basis determine and adjust the production mix. Risks and uncertainties often direct agents to invest in flexible power production technologies with short time periods for the return of the investment, short construction time and the ability to switch between fuel types.

In the medium and long run power companies are dealing with decisions of undertaking new investments to move towards a less carbon intensive technology, thus confronting with questions whether to build a new power plant and how and when to retire an old plant. Due to the fact that economies of scale favor the development of large power facilities with very long plant lifetimes in order to minimize the cost of unit production, these investments are capital-intensive and long-lasting and the decisions which have to be taken are driven by significant levels of uncertainty, particularly relating to the price and volume of electricity sales and the price of input fuels.

In order to make the decision whether to invest or not a power utility needs to make the best possible estimation of the expected profitability of the investment. The profitability of a power plant investment can be calculated as follows:

Profitability per unit of electricity (€/MWh) = Electricity price (€/MWh) – fixed cost (€/MWh) / running hours (h) – variable cost (€/MWh)

Equation 2.1: Power plant Profitability

The sum of the fixed cost divided by the running hours and the variable cost is called the Long Run Marginal Cost (LRMC). The primary objective of power generation companies is to maximize profits by optimizing the use of their generation capacity given the electricity price they can receive at any given time which should be high enough to cover up the LRMC in order to make the investment profitable. We will discuss further this topic in section 2.4.2 .

2.4 Uncertainties concerning Energy Prices

As was pointed out in section 2.2, the most fundamental risk for power generation companies, in competitive markets is the electricity price risk which is the major driver for power plant investment profitability above fuel price and carbon price. Figure 2.1 shows how these prices interact and how they have evolved since the introduction of the EU ETS.

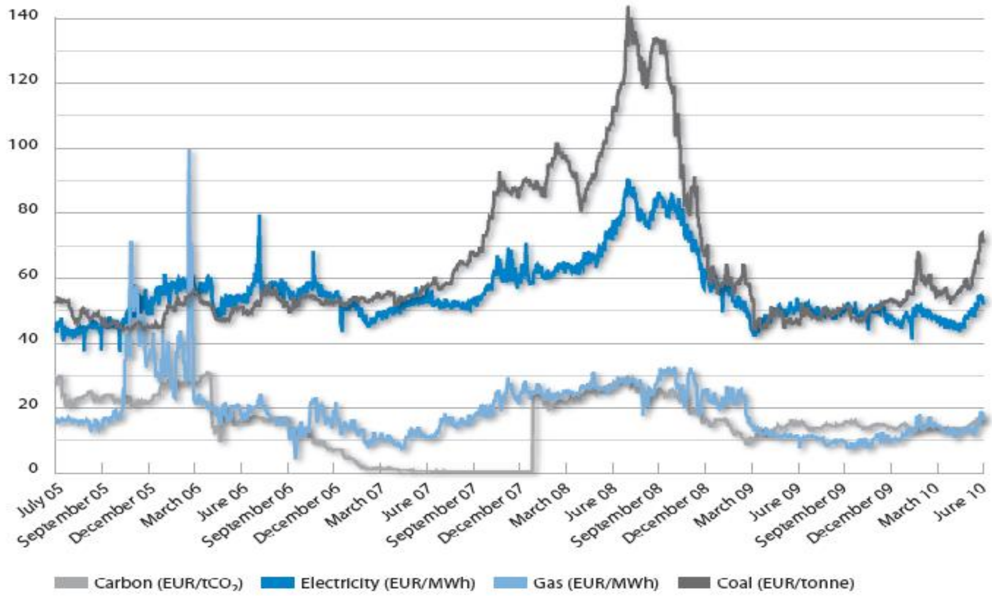

Figure 2.1: European daily Prices of a range of commodities: gas, electricity, coal and emissions, 2005-2010, source OECD 2011[12].

Next we will give a brief outline of the energy price evolution during the first half of 2011 in Europe and discuss which factors are actually the main drivers of electricity price risk in order to get an idea of the interconnections.

2.4.1 Energy prices in Europe for the first half of 2011

According to EON 's Interim Report II/2011[13] four main factors drove electricity and natural gas markets in Europe in the first half of 2011:the rising international commodity prices (especially oil, coal and carbon-allowance prices), macroeconomic and political developments besides weather and natural disasters. At the start of the second quarter energy prices continued to be driven by the unrest in North Africa and the Middle East, the earthquake and tsunami in Japan. As the quarter progressed, however, Greece's debt crisis and worse prospects for economic growth in the EU became the main driver factors, particularly in carbon allowance prices which have dropped significantly and subsequently influenced power prices.

Concerning fuel prices after at times exceeding 125$ /barrel in April due to the unrests in North Africa and the Middle east and supply disruptions from Libya the price fell sharply in May, rose in early June falling again on the announcement by the IEA that IEA member states planned to release 60 million barrels from their emergency stocks in order to relieve tightness in the oil market.

European forward gas prices declined slightly in the second quarter of 2011.After milder weather sent gas prices lower in April, prices reaches a high in May because of outages at production facilities in Norway and Germany's announcement that the shutdown of eight nuclear power plants would be permanent. Overall gas prices experienced a substantial recovery in the first half of 2011 following the positive developments in fuel prices. The December carbon futures contract for next year delivery of EUA which had risen to about 18 per metric ton by the end of March on increase power generation from natural gas and coal due to Germany's moratorium, subsequently trended downward with the drivers for the low emissions prices being Greece's debt crisis and worse economic prospects for EU growth.

In Germany baseload electricity futures prices for 2012 delivery increased in the first half mainly by 10% mainly because of the Japan crisis, Germany's moratortium concerning the immediate phase out of eight nuclear reactors and rising gas coal and carbon prices. Finally they fell through the end of June by 3€ to 57 € per MWh tracking the decline of carbon-allowance prices.

2.4.2 Electricity price uncertainty

Electricity price risks arise because of uncertainties about future prices for electricity. These in turn arise for a range of reasons, from volatility in fuel prices to large scale economic events or political changes or problems with power stations. Market structures under liberalized markets differ between countries and are subject to change over time**.** Before liberalization, regulated electricity prices corresponded to average costs of power generation. In a liberalized competitive power market instead, prices are expected to equal short-run marginal costs. In the long run, the competitive price level should not exceed long-run marginal costs of new power plants which are the sum of the fixed costs and the variable costs divided by the running hours. Power generation companies will always attempt to shape their decisions with long term impacts so as to move from the short run marginal cost curve (which includes capital costs and incorporates the generation marginal costs) to the long run marginal cost curve (Weber and Swider, 2004 [14]).

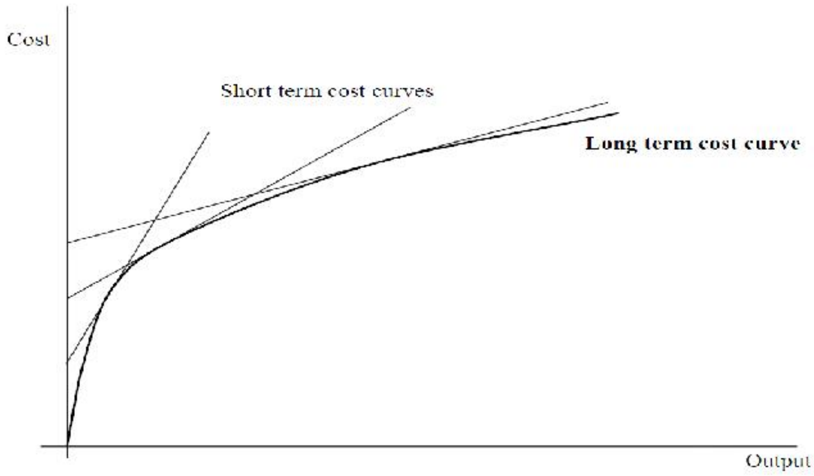

Figure 2.2: Long-term cost functions as lower bound to short term cost functions, source Weber and Swider, 2004 [14]).

However, in a noncompetitive environment prices may exceed the former price level because of either mark-ups or strategic investment withholding. Figure 2.3 compares these different price development scenarios.

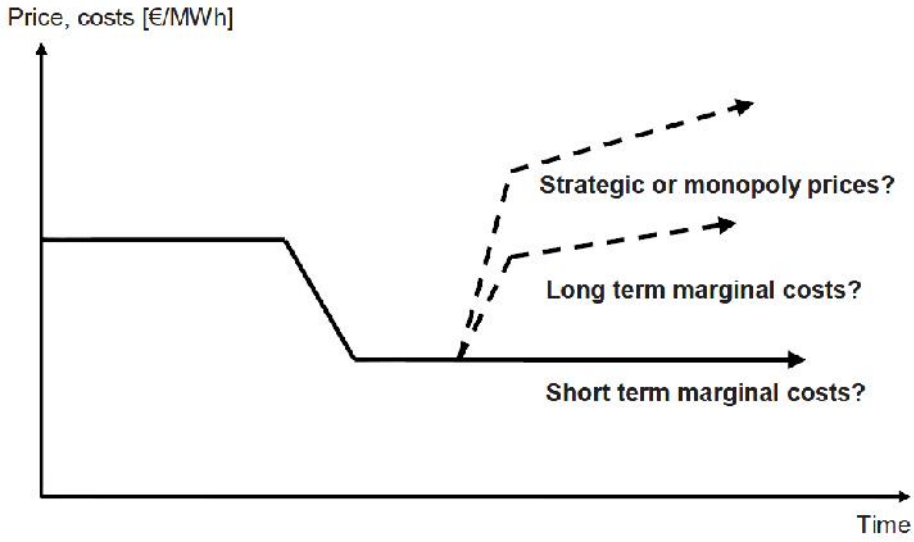

Figure 2.3: Price scenarios in liberalized markets, Handbook Utility Management, 2009 [15].

Under the above assumption of unregulated markets with the electricity price depending on the short run marginal costs of the marginal unit, the factors that influence electricity prices are the following:

- Fuel and carbon price uncertainty which affect the costs of the marginal unit and influence the clearing price.
- A change of electricity volume demand or supply can switch the unit that sets the price. On the short-term, such an effect can be for instance due to feed-in from electricity produced by renewable sources which must be integrated into the grid due to legal obligations. On the long-term, such changes might be due to a changing electricity demand or modifications of the power generation fleet which in turn can be triggered by future political decisions or the behavior of competitors, which are both uncertain.

Another important source of electricity price risk results from the long run investment dynamics that arise in competitive electricity market environments (Gross et al., 2007[16]). If flexibility exists to delay investments and if electricity prices are low, i.e., near the short-run marginal cost of power production (which in turn is influenced by the carbon price), then there might be too little incentive to invest in generating capacity. Later, when capacity reserves diminish and the market becomes tighter, a boom phase may be triggered during which new capacity is brought on line in order to gain from the higher prices and to gain market shares. Overall, such boom–bust cycles can lead to cycles in both electricity prices and security of supply (Figure 2.4).

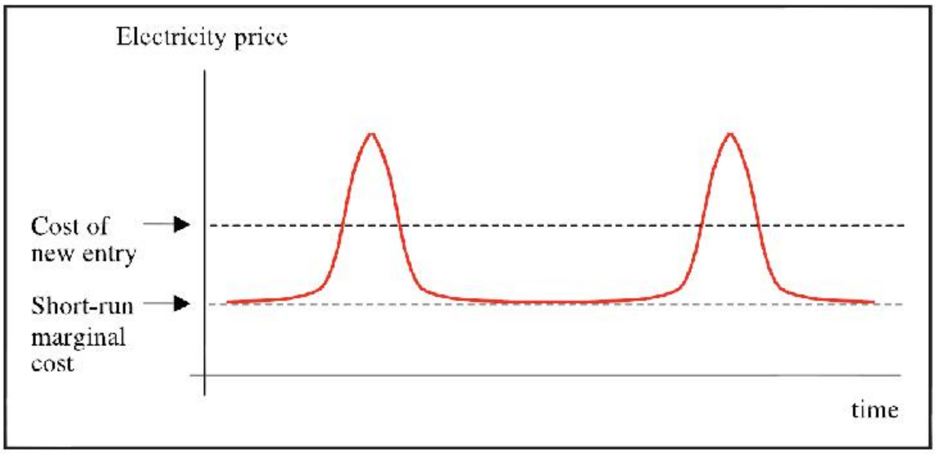

Figure 2.4: Investment and price cycles in a competitive market (Gross et al., 2007[16]).

2.4.3 Fuel price uncertainty

Fuel price uncertainty has a significant effect on generation costs. In most countries the biggest part of electricity being produced comes from fossil fuels. Depending on the type of power plant, fuel costs could account up to 30% (for coal plants) and up to 65% (for CCGT plants) of the total costs. Consequently, the major uncertainty in terms of price fluctuations in the fuel markets especially the one for natural gas, is being reflected in thermal power plants generation costs.

Furthermore fuel prices influence the electricity price. If we consider having unregulated markets, the electricity price corresponds to the short run marginal costs of the most expensive unit in the merit order producing electricity. The price-determining unit is often a gas or a coal plant, so fuel price volatility influences electricity prices as well. (Figure 2.5 shows recent trends of fossil energy prices concerning the past 5 years while Figure 2.6 shows these costs translated in Power plant fuel costs).

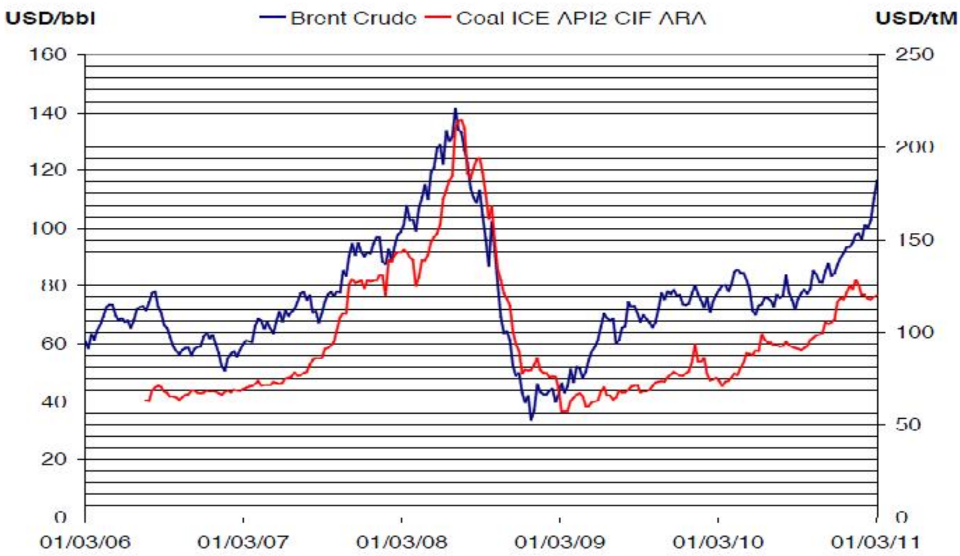

Figure 2.5: Trend of fossil energy prices source, Aıd R., 2011[17].

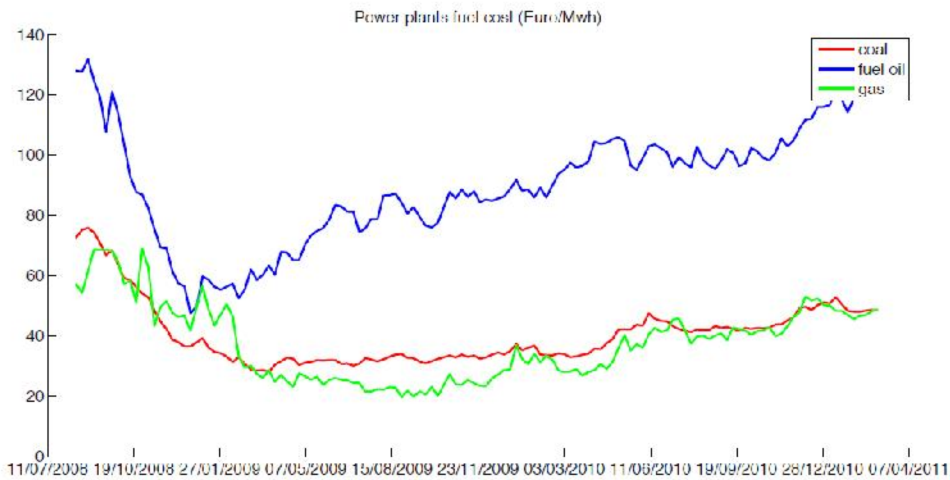

Figure 2.6: Power plant fuel cost (Euros/Mwh) source, Aıd R., 2011[17].

2.4.4 Electricity demand and uncertainty about the competition's decisions

Electricity demand and the uncertainty about the competition's decisions may firstly change the amount of electricity that is produced by the considered units and secondly, influence electricity prices by changing the marginal unit. The decisions of the competitions have a similar effect as changes in the electricity demand.

Furthermore, additional units from competitors may decrease the amount of electricity produced by the own units and on the other hand, even if they have no impact on the electricity production of the own units, they may change the electricity price by changing the marginal unit.

2.5 Regulatory risks and climate change policy

Power utilities act in energy markets under a framework set by political decisions and are therefore vulnerable in regulatory risks (Figure 2.7). E.g., regulatory measures such as imposed carbon policies or the recent reconsideration (i.e. moratorium) of the German nuclear policy can have significant impacts on electricity generation. For Europe, the major political decision which has had a catalytic impact on European electricity generation has been the implementation of the EU-ETS, established by Directive 2003/87/EC. Due to its coming to force, new costs were created, which have to be taken into account for power plant investments.

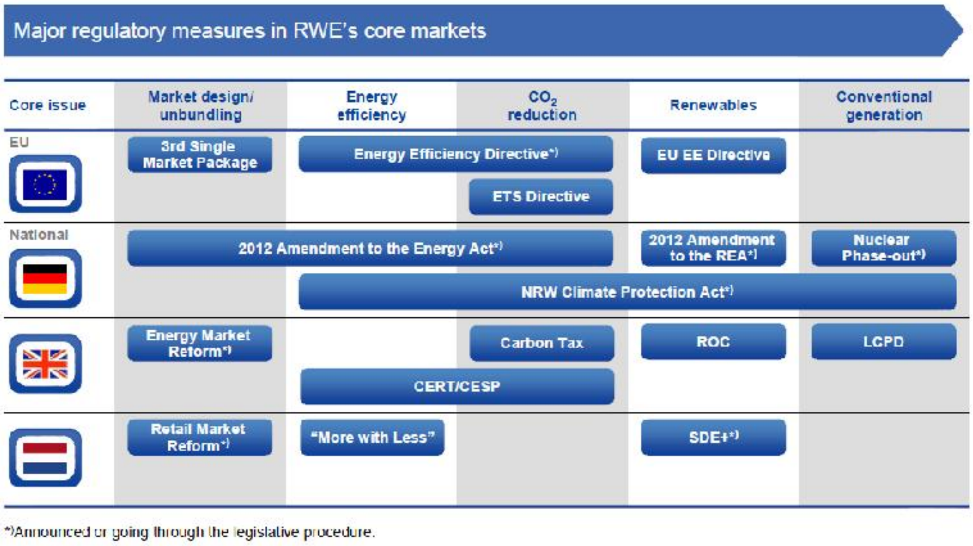

Figure 2.7: Major regulatory measures in the european utility market for a power utility i.e. RWE [5].

Furthermore there are more uncertainties in climate policy, such as the political context within which climate policy is developed (e.g. the level of government support for climate policy measures or concerns about energy security) and the manner in which it is being implemented (e.g. if government is seen as committed to climate policy). Some of the sources of uncertainty faced by electricity utilities are briefly listed below:

- The degree of government support for policy action on climate change, over the short and long term.

- Whether there will be a post-2012 international regime, and whether this will be target- or process based.
- The specific policy instruments used.
- Differences in implementation between different countries.
- The future price of carbon.
- Allocation rules.
- Subsidy levels for specific technologies.
- The timing of policy responses.
- The response of other companies to specific policy measures.
- The degree of support for climate policy measures among companies and investors.
- The relationship between climate policy goals and other policy goals such as energy security.

The evaluation beforehand of the effectiveness of undertaken climate change policy measures, faces complications which are based on uncertainties dealing with technology costs and on the impossibility to forecast the responses of the players affected by the policy measures. There is a need for an equilibrium between certainty and flexibility concerning climate change policies: These need to be neither too fixed, because this would push policy makers to actions that would be either too strict or not strict enough, with limited freedom for adaptation, nor too flexible, because this would create an additional cost to companies being forced to meet decisions on a volatile policy environment basis.

In the following section we will discuss the impact of risk on the very important issue of generation technology and as an example we will mention carbon capture and storage (CCS).

2.6 Risks and Investments in Different Generation Technology Choices

Economic, political, legal and force majeure risk factors affect different generation technologies in different ways. Some risks are inherent to the technology involved while others involve the interaction of technology and the environment in which the generating company operates. E.g., the investment costs of a coal plant are very high, but the fuel costs (and hence operating costs) are relatively low with the coal prices at the same time having in comparison to other types of fuel very low volatility. Coal-fired power stations are therefore more exposed to the financial risks concerning the repayment of the initial capital of the project based on future electricity volumes and prices. A similar effect concerns renewable technologies such as wind and solar power which have zero fuel cost, and hence low operating costs, with the main costs being the initial capital. On the contrary, gas plants have relatively low capital costs and flexible operations, but high fuel price dependency leaving such projects exposed to uncertainties in the future gas price.

A qualitative comparison of the risk characteristics of different types of generating power plant technologies is shown in Table 2.2.

Table 2.2: Qualitative comparison of the risk characteristics of different generation technologies source, International Energy Agency, Power Generation Investment in Electricity Markets (Paris: IEA, 2003[18]).

Technology	Unit size	Lead time	Capital cost/kW	Operating cost	Fuel cost	CO_2 emissions	Regulatory risk
CCGT	Medium	Short	Low	Low	High	Medium	Low
Coal	Large	Long	High	Medium	Medium	High	High
Nuclear	Very large	Long	High	Medium	Low	Nil	High
Hydro	Very large	Long	Very high	Very low	Nil	Nil	High
Wind	Small	Short	High	Very low	Nil	Nil	Medium

Regulatory risk can influence decisively the generation technology choice. According to Blyth, 2007 [1], technologies which are low-carbon and additionally high capital investments e.g. nuclear power and renewables , are vulnerable to climate change policy changes. Due to the fact that the cost basis of such technologies is not affected while operating inside an emissions trading scheme, these gain only indirect benefits, which consist merely of the pass-through of costs from the fossil fuel generating plants to the price of electricity. If electricity prices increase they succeed additional revenues for all types of generators, with the effect on profits not being the same for all, though. Concerning fossil fuel generators profits, their rise is weakened by a simultaneous increase in costs caused by the additional emissions costs but at the same time this weakening of profits makes their future profit margin less sensitive to big CO_2 price variations and therefore less exposed to climate change regulatory risks than nuclear or renewable generators.

Research and investments in a new technology called carbon capture and storage (CCS) is affected as well since the introduction of the EU ETS. This technology takes CO_2 from combustion plants, transports it through pipelines and then pumps it down into different types of sites for long-term storage. According to Hoffmann, 2007[8] however, while this technology allows the reduction of the CO_2 emission of fossil fuel power plants by up to 90%, it also reduces the efficiency of power generation and only becomes profitable at allowance prices of about 30 euros per ton CO_2. Given the high price volatility of allowances, the regulatory uncertainty that surrounds the EU ETS, and uncertainties about the feasibility of CCS technology, investments are associated with a high risk. Quoting an interviewee (Hoffman, 2007[8]):

"*For us, it is a huge risk to invest in CCS because we do not know whether it will be profitable after 2012. We need a CO_2 price of Euro 30 per ton. But then the EU cannot perform a solo attempt and needs in the long term the USA, China, and India on its side. These countries will, however, not take part in a system which has a price of over Euro 5 per ton. This means a high risk and poses the question whether CCS will be profitable*".

From the perspective of the CO_2 emitter, the key risks associated with this new technology are uncertainty over the costs of the CO_2 separation equipment, over the performance and security of the storage sites and over how much the avoidance of emissions will be worth in terms of reduced costs of emitting CO_2. If coal plants are built in a suitable way and at a proper location, CCS can be relatively easily retrofitted at a later date. It therefore provides coal plant with a good hedge against uncertain future CO_2 prices. If CO_2 prices remain low, the coal plant can continue to be operated without the capture plant, but if they rise sufficiently high, then CCS can be retrofitted. The existence of CCS as a future retrofit option therefore makes current investment in coal look significantly more attractive. Thus investment in coal-fired power generation could accelerate while investment in CCS itself may not be implemented until carbon prices are significantly higher than they are today – a situation that would lead to an increase in emissions in the short term unless overall emissions are capped.

2.7 Conclusions

In this chapter we pointed out that a power utility needs to make the best possible estimation of the expected profitability of an investment before it makes the decision whether to invest or not.

The task to optimize power plant profitability is becoming more and more complex due to its dependence on various risks which include the highly uncertain and volatile electricity, fuel and carbon prices.

Consequently, investors have to use more sophisticated approaches to determine optimal investment levels and technology choices than they used in regulated markets.

CHAPTER 3

CARBON EMISSIONS POLICY

3.1 Introduction

An introduction to the different carbon policies will be provided in this chapter, with special focus on the European EU Emissions Trading Scheme. We will focus on the basics of the regulatory mechanisms to reduce emissions and provide a background for analysis on the emissions trading scheme and its impact on the investments of electricity producers.

The first section gives a broad overview of economic instruments for environmental policy while discussing the major types of carbon policy. The second section will look at how emissions trading has functioned as a policy instrument in Europe by looking at the specifics of the EU ETS .

We will conclude with an analysis of how uncertainty in CO_2 prices arises due to climate negotiations and also due to the market structure of the EU ETS. This weakens the price-signal created by policy, decreasing the incentive for companies to invest in abatement.

3.2 Economic Instruments for Environmental Policy

Economists perceive environmental problems as a problem of externalities. Considering that a negative externality is a cost while a positive externality is a benefit economists argue that global climate change is a negative externality. Although there is both a cost for the greenhouse gases damages and a scarcity in the capacity of the atmosphere to absorb them, the lack of a market price means the cost is borne by society and is external to economic decision-making.

Economic instruments are used for environmental regulation in order to provide incentives through price-signals rather than through the explicit instructions of command-and-control (CAC) (i.e. (Stavins, 2002[19].). In this way, corporations take measures that are in their own self-interest which will then collectively meet policy goals.

3.3 Carbon policies and their effects

3.3.1 Introduction

Global climate change can be considered as the "*Tragedy of the Commons*" for which no effective global coordination, regulation, or enforcement has yet been developed [Hardin G. [20]. This has not happened for a variety of reasons. First, CO_2 is a global pollutant, which implies that the regulation of local emissions needs to be coordinated worldwide. Second, fossil fuels make up the most used fuel type of the industrialized economies: Reducing or replacing their consumption is difficult and costly. The price of carbon is the generic term for placing a price on carbon through either subsidies, a carbon tax, or an emissions trading ("cap-and-trade") system. Following we will discuss the most important of these carbon policies.

3.3.2 Carbon taxation vs emissions trading

The price of carbon is the generic term for placing a price on carbon through either subsidies, a carbon tax, or an emissions trading ("cap-and-trade") system. Table 3.1 presents an overview of the present prevailing types of carbon policies.

Table 3.1: Electricity generation in a carbon constrained world: characterization of carbon policies Chappin.E., 2010 [21].

Policy Instrument		Price	Volume of Emissions	Allocation of Emission Rights	Implemented in Practice
Carbon taxation		Set by government	Not limited	Can shift between sectors	Yes
Emissions trading	Cap and trade	Market based	Capped[2]	Grandfathering/ auction[3]	Yes
	Performance standard rate	Market based	Not limited	Benchmarking and performance	No
Command and control		No price	Regulated per source	By government, per source	Only for other pollutants

The growing consensus that CO_2 emissions need to be stabilized and then reduced during this century has led to much interest in achieving cost-efficient emission reduction through incentive-based instruments rather than command-and-control regulation. Taxes and cap-and-trade systems can be viewed as extreme examples of the two main market-based approaches that are available to correct an emissions externality. To reach a pre-defined emissions target the government can use price or quantity policy instruments, i.e. a tax or a cap-and-trade approach. Emission rights (allowances or permits) are either supplied (with infinite elasticity) at a fixed price (i.e. a tax) or (with zero elasticity) at a fixed supply (i.e. a cap). Description of both policies follows:

1. **Emissions (carbon) taxation**: For every specified amount of emission a tax has to be paid. With this policy instrument it is not guaranteed that the emission objective is realized. Installations reduce emissions until further reductions have a higher cost than paying the emission tax.
2. **(Emissions) cap and (allowance) trade:** Each source is allowed to emit until a specified cap. This is direct regulation and an emission objective can be realized. In this system a specified, gradual declining, amount of allowances is allocated and the allowances can be traded. This is a market based policy and an emission objective can be realized and this can in theory be done at the minimum cost.

An incentive-based policy instrument intends to create an effective carbon price signal. A carbon tax represents a more stable price signal but it is difficult to establish ex ante which tax level would be required to achieve the desired emission reduction. On the other side, cap and trade tends to be a more complex regulatory scheme than the carbon tax and it leads to uncertainty regarding the price of carbon emissions. This uncertainty occurs because, unlike a tax, the price of an allowance fluctuates in a dynamic, market setting manner and can plummet quite sharply when supply increases and/or demand decreases (for e.g. like the one noticed during the 2007 global recession). Consequently this has led to fears that the uncertainty of the carbon price might lead investors to defer investments into “clean technologies”.

3.3.3 Hybrid policies

Recently several observers of the carbon market, mainly from the UK, proposed the introduction of CO_2-price floors and ceilings containing elements of both price and quantity regulation, which according to them could reduce the uncertainty of future CO_2-prices.

Such an approach was named a hybrid tax and trading approach (PriceWaterhouseCoopers, 2009[22]).

Wood and Jotzo (2010) [23] point out that price floors in greenhouse emissions trading schemes can have advantages for technological innovation, price volatility and management of cost uncertainty (although implementation has potential pitfalls). Under a pure cap-and-trade scheme, the regulator has to continually react to decreasing carbon prices by adjusting emissions targets in order to stimulate further emissions reductions, with the carbon price floor, on the other hand, he has the potential to induce emissions reductions automatically. By using price ceilings and/or price floors it is possible to generate a regulation system which lies between the tax and the cap-and-trade schemes. The narrower the price band, the more closely it resembles a pure carbon tax, while the wider the band, the closer it comes to a pure emissions trading scheme.

Price ceilings are a widely recognized option to limit the risk that carbon prices exceed acceptable levels if constraining emissions turn out to be more expensive than expected. They thus provide a reduction in upside price risk to emitters. The mirror instrument is a price floor, which would ensure a minimum price on carbon, thereby providing a downside risk reduction for investors in low emissions technologies. It would also allow emissions to undershoot the target set by the administrator, thus providing more abatement if costs are lower than expected (Wood and Jotzo, 2010[23]). Both price ceilings and price floors can reduce risk and price volatility in carbon markets, which has been of concern in all types of emissions trading systems.

Although there are alternative mechanisms, such as carbon taxes or fees on emissions, cap-and-trade schemes have emerged as the prevailing tool for addressing GHG emissions in the EU and elsewhere..

Next we will focus on cap-and-trade schemes, the way they are functioning and finally we will focus on EU ETS.

3.4 Framework of a market-based solution: cap-and-trade schemes

The framework for emissions trading as a policy instrument developed on the basis of the presence of pollution as an externality which could be corrected if there was an economic incentive and a possibility for actors to bargain. Property rights define the right to pollute, thus the market would play a role in pollution control policy (Tietenberg, 2006[24]). The government, as the owner of a natural system, could implement a cap on an acceptable level of pollution and issue an amount of emissions rights up to this amount. Then it would simultaneously pass a law that required anyone discharging pollution to hold the rights to do so. The rights would be fully tradeable, allowing the market to price the rights accordingly and freeing the government of the administrative and political burden of setting the price. Experiments with emission trading systems started in the 1970s in the US (Tietenberg, 2006[24])) resulting in 1990 in the CO_2 emission trading scheme.

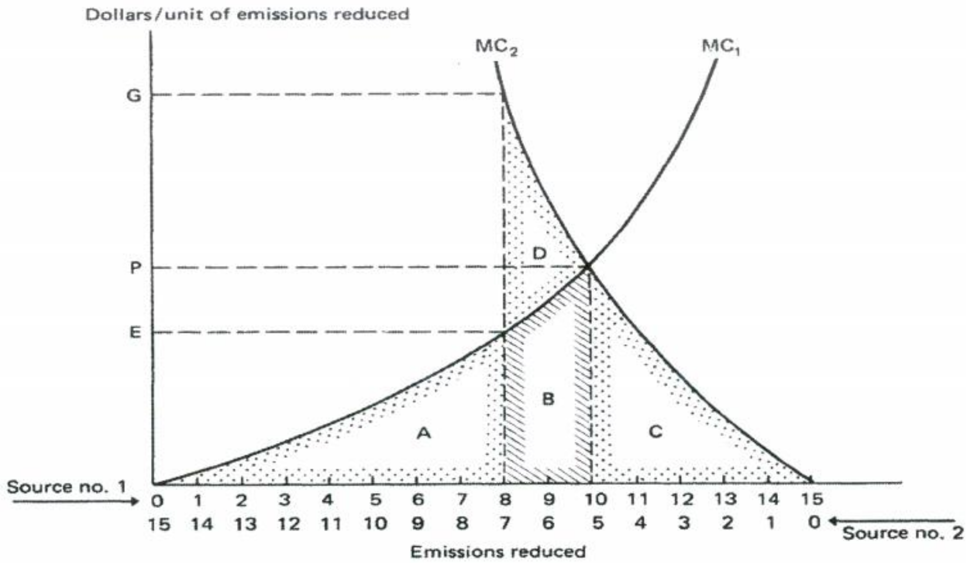

Figure 3.1: Cost-Effectiveness and the Emission Permit System, Source 1=7 allowances; Source 2=8 allowances, C=marginal cost of control for Source 2, A=marginal cost of control for Source 1, B=the allowance price in trade (equilibrium, 5 and 10), (source: Tietenberg T.H.,, Environmental & Natural Resource Economics ,ch.15).

3.5 Outline of an emissions trading scheme

First, the total allowable emissions are limited (cap), and a corresponding number of allowances (also called permits) are created and distributed, which in turn may be bought or sold on a market (trade). Second, regulated emissions are monitored and verified and at the end of a compliance period, typically a calendar year each unit has to return allowances equivalent to the amount of emissions to the regulator. In theory, a firm will minimize the cost of compliance by abating pollution until its marginal cost equals the market price of an allowance. For this reason, cap-and-trade programs are cost-effective, i.e. achieve the desired amount of emissions reduction at the lowest possible total abatement cost. An additional goal of a cap-and-trade system could be to promote technological innovation to a greater extent than automatically induced by the long-term price signals from a market. In such a case, uncertainty over future prices may be a good starting point for a policy intervention, since it plays an important role for investment decisions.

3.6 Description of the EU ETS

Although emissions trading systems have been established in at least six states in the United States, the most recent application of a cap-and-trade mechanism and at the same time the largest in the world is the European Union Environmental Trading Scheme (EU ETS).

Its main pillar is the carbon market in which emission allowances can be traded with the expectation to succeed an economically optimal distribution of emissions among agents. It remains to be seen, however, whether it creates sufficient investment incentives for electricity producers, because as mentioned above, the price of emission rights is volatile and the time horizon of the ETS is limited.

Due to a significant degree of uncertainty regarding the structure of a future global agreement on climate change, it is crucial for the EU to find the right balance between policies striving towards a low-carbon economy and maintaining competitiveness of European industry. The objective of EU ETS is to provide incentives (i.e. price signals) to reduce emissions at least-cost while moving the economy onto a lower carbon level. The EU ETS, which came into force on 1 January 2005 and was established through Directive 2003/87/EC:

- Phase I : 2005 to 2007, first trading period (trial period)
- Phase II: 2008 to 2012, second trading period
- Phase III: 2013 to 2020, third trading period

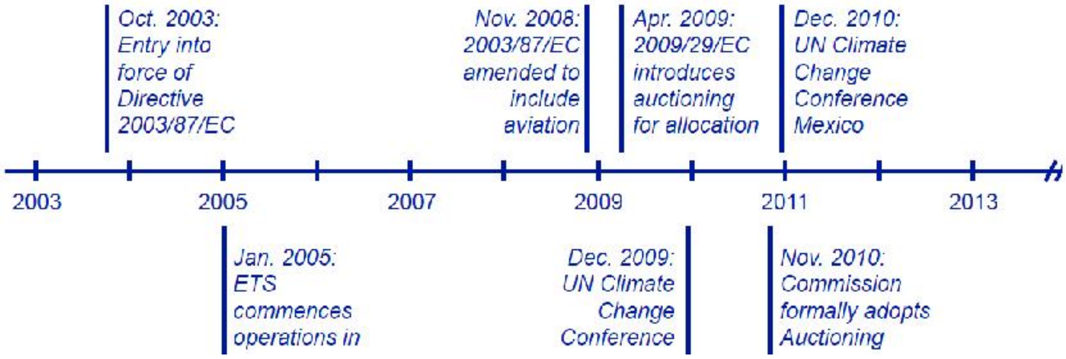

Figure 3.2: Structure and history of EU ETS, source Deutsche Bank Research,2009[25].

It is a 'cap and trade' regime which sets limits on carbon dioxide emissions from currently more than 12,000 installations representing over 2 billion tons of CO_2 (almost half of the EU's greenhouse gas emissions), thus being the largest emissions trading scheme in the world. It currently includes combustion plants, oil refineries, coke ovens, iron and steel plants, and factories making cement, glass, lime, brick, ceramics, and pulp and paper. Other sectors, e.g. aviation, will be brought into the EU ETS in 2012. Within these sectors, all facilities above a certain size (the specific thresholds are set by national governments) must hold emission certificates to cover their CO_2 emissions. Under the scheme, each member state allocates a certain number of allowances (allowances to emit one ton of CO_2 equivalent, referred to as European allowances or EUAs) to its industrial installations based on the country's National Allocation Plan (NAP).

The EU Commission decides if the NAP fulfills criteria imposed by the Emissions Trading Directive and most importantly whether the request is aligned with the member state's Kyoto target. Once this is established, individual states are free to allocate permits to industrial operators covered by the scheme. There are several types of allocation methods. Allocation can be through grandfathering where allowances are given for free according to historical emissions. There can also be an allowance auction where companies bid for a given quantity of allowances.

Once an initial allocation is made, polluters can trade. Trading is advantageous because it allows companies to benefit from differences in abatement costs. Operators must have a quantity of carbon credits that matches their verified emissions at the end of each year. Those that have a surplus can sell privately or in one of several established markets. Those that are short must buy permits and if they fail to do so, must pay a fee. The standard carbon credit is known as an European Union Allowance (EUA). There are additional types of permits linked to the EU ETS. EUAs can be substituted with what are known as Certified Emission Reductions (CERs) which come from United Nations validated abatement projects in developing countries. There are also Emission Reduction Units (ERUs) which come from Joint Implementation Projects and are also UN validated.

The price of the allowance provides a price-signal for changes in operation behavior. It encourages corporations to take abatement measures by acting on their own self-interest to minimize their costs. While the EU ETS provides an incentive, it does not guarantee that reductions will take place at individual installations. This will be dependent on the decisions of firms and individuals.

The ETS significantly alters the competitive landscape in the EU. Opponents argue that EU industries are put at a competitive disadvantage to the same industries abroad and therefore outside the ETS. This could cause companies to either move production abroad or increase production in plants based abroad, and thereby never actually achieve emissions abatement.

3.6.1 The three Phases of EU-ETS

The establishment of the ETS is a dynamic process and has been set up in three phases. Due to the fact that the carbon allowance market is practically a virtual market with no natural demand for carbon allowances, it depends absolutely on the regulatory framework.

Phase I from 2005-2007 was the ‘’trial phase’’. In this phase, all installations participating in the scheme were provided with carbon credits corresponding 100% to their respective emissions. Unfortunately, after a year of operation, it was discovered that most installations had been oversupplied with carbon credits (over-allocation) on the basis of falsely calculated benchmarks. Consequently the carbon market then collapsed making allowances worthless. (Figure. 3.3.).

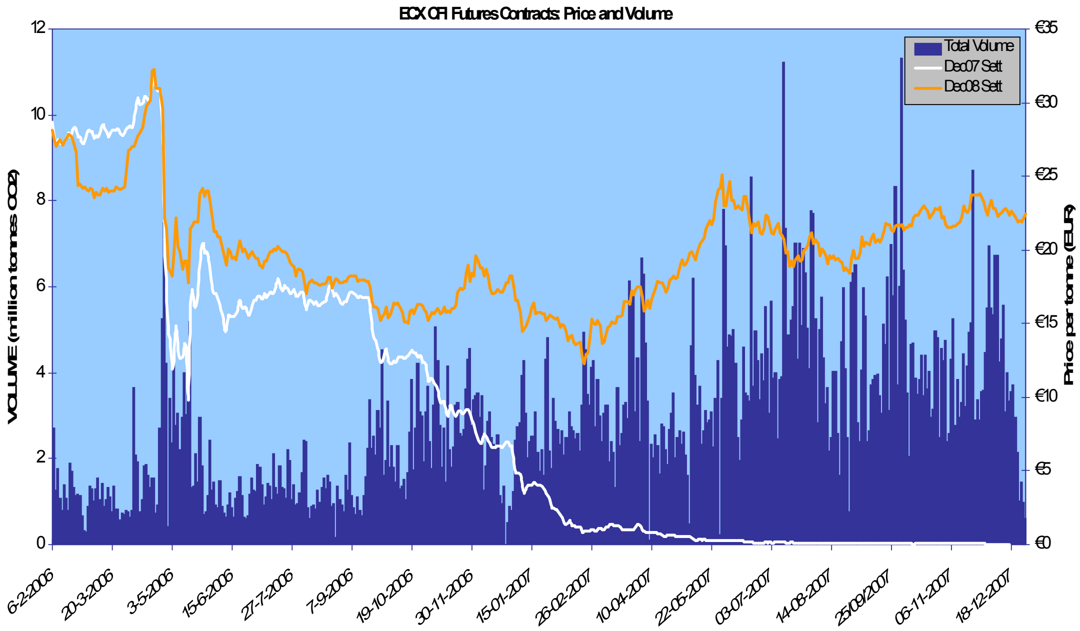

Figure 3.3: Carbon price in Phase 1: Over-allocation became apparent when emission data for 2005 were published (De Bruyn, S.M, 2010[26]).

Phase II is the phase we are currently in, and runs from 2008 to 2012. Credits from this phase can be banked to Phase III, meaning that no carbon price fall is expected. However, the current global financial crisis has caused industrial production to slow down, thus causing a decrease in the power demand. Consequently this implies that less emissions are being produced and, with the annual quota of free carbon credits fixed, the carbon credit demand collapsed. Finally, traded allowance volumes during this phase have been multiple times higher than the volume needed to cover short and long allocations, a fact which indicates the existence of a significant grade of speculation.

Phase III is planned to run from 2013-2020. It is anticipated that the demand for carbon credits will soar if and when the economy recovers from the financial crisis, though pessimists forecast a non-growth ,''lost decade'' for the world economy and particularly for Europe which would become the tombstone of the EU ETS. The preliminary plan of the bureaucrats from Brussels is that by 2020 there will be a 21% reduction in allowances compared with 2005. If, however, a post-Kyoto international agreement would be reached on specific reductions, this percentage could eventually increase to 30%. Taking into consideration the debacle of the Copenhagen conference in 2009, the fact that the Cancun conference in 2010 was doomed to failure before it even begun and the zero expectations of the Durban conference in 2011, the future of EU ETS looks as if it is heading towards its end. A change set to be implemented during this phase is that previously freely allocated allowances are about to be auctioned leaving thus to the market forces to guarantee a more effective allocation of allowances. Nevertheless according to an exemption set by the EU, industries exposed to a significant risk of not being competitive within the EU will be granted 100% of their allowances free of charge in Phase III.

3.7 Creating an effective price signal

Incentive-based policy instruments such as the European emissions trading system and carbon taxation use market signals to influence decision making and behavior.

As already mentioned in sector 3.2 the economic theories behind emissions trading tell us that climate change is an externality and in order to correct this, there must be a cost for the use of a resource.

The premise of the EU ETS rests on the assumption that a price, through the self-interested behavior of individuals, will promote changes in behavior. This is also referred to as a price-signal. In the electricity sector, the price-signal will do two things. For consumers, the price of electricity will include the costs of the damages caused by its CO_2 emissions. This increase in price will reduce consumption to some degree depending on the elasticity of demand. For producers, it will encourage changes in how electricity is generated. Both consumers and producers will play a role in reducing emissions but we know that demand for electricity will continue to grow over the next 30 years so there will need to be investments in low-carbon generation. In light of a significant degree of uncertainty regarding the structure of a future global agreement on climate change, it is crucial for the EU to find the right balance between policies striving towards a low-carbon economy and maintaining competitiveness of European industry. The objective of EU ETS is to provide incentives (i.e. price signals) to reduce emissions at least-cost while moving the economy onto a lower carbon level.

The reality that has been experienced in the implementation of the EU ETS shows that the price-signal is not as straightforward as theory suggests. Several examples have been given of how specific aspects of the policy can alter the price-signal. E.g., the free allocation of permits. In Phase I and II, grandfathering of permits was shown to have the effect of raising electricity prices but not promoting reductions in emissions (Sijm et al., 2006[27]).

There was also the effect of volatile carbon prices due to uncertainty about levels of emissions in relation to the cap. In May 2006, the price of permits plummeted because of this. These issues weaken the price-signal of the EU ETS. The biggest barrier to widespread investments remains uncertainty over the future price of CO_2. Companies faced with the choice of an uncertain cash flow may choose to wait for policy signals to become clearer. By forgoing investment, a company may have a clearer picture of future scenarios but this option will come at the cost of lost income had the investment been pursued earlier (Blyth et al., 2007[28]).

It is important to take uncertainty as a serious barrier to the functioning of the EU ETS. It can be said that two major sources of uncertainty have developed in the EU ETS, uncertainty over the future course of climate policy and also uncertainty related to the structure of the carbon market.

3.8 The economic downturn and Europe's emissions market

The second phase of the EU ETS faced the effect of the economic and financial crisis that began in late 2008. The recession led to a more dramatic decline in emissions than most players could have imagined. Based on data released on April 1, 2010 [29], http://ec.europa.eu/environment/climat/emission/citl_en_phase_ii.htm, GHG emissions from reporting EU ETS installations fell more than 11% in 2009, which is the biggest year-on-year drop since the EU ETS began in 2005. The data from 9,866 installations show that their total emissions decreased to 1.69 billion tons in 2009, 214 million tons less than in 2008. (State and Trends of the Carbon Market 2010, [30]).

Utilities experienced relatively modest declines in demand, although they are still potentially short in this Phase and will need to hedge their future electricity sales beyond 2013.

A positive sign deriving from the financial crisis concerned in my opinion the efficiency of the EU ETS as a market mechanism because it has been able to reflect macro-economic trends. To be more specific, the fact that carbon prices fell along with the prices of mature energy commodities as the global economic crisis deepened, and rebounded as soon as there were signs of recovery, suggests the market is both efficient and rational

3.9 Conclusions

The price of carbon dioxide emissions is acknowledged to become an important factor affecting future investment decisions. Greenhouse gas emissions are economic externalities whose cost is borne by society but is external to economic decision-making. Regulators try to correct this by giving a price to carbon so that polluters have an incentive to adjust emissions to a level that is socially optimal. The EU ETS has integrated the externalities of greenhouse gas emissions into financial transactions. The policy is now in its second phase of implementation and is due to expand in its third phase.

In Europe, electricity generation accounts for one third of CO_2 emissions. The success of an emissions trading scheme therefore depends in significant part on the reduction of emissions from the power sector. The success of the EU ETS in reducing emissions in the electricity generation sector will depend on its ability to push power companies to invest in clean-power through a clear market signal.

Some of the biggest barriers are conditions of market and policy uncertainty which increased risk for abatement projects. The problem of policy uncertainty is due to the fact that CO_2 permits are a virtual commodity with no natural demand except that created by legislators. The EU is in a situation where it depends on an international climate agreement which seems very distant considering the failures in Copenhagen and the outburst of the economic crisis.

CHAPTER 4

THE FUNDAMENTALS THEORY OF THE EU ETS PRICE FORMATION

4.1 The fundamental drivers of carbon price

CO_2 price is determined by demand and supply on the CO_2 market. Total supply is dictated by the UNFCCC allocation quota which is lowered every year (with a small amount of additional supply created by carbon credit generating projects), with the number of allowances as mentioned in section 3.7 distributed, being determined by each member-state through National Allocation Plans (NAPs), which are then harmonized at the EU level by the European Commission.

Demand is determined by industrial and energy sector production. In turn, the level of emissions depends on a large number of factors, such as unexpected fluctuations in energy demand, energy prices and weather conditions. The demand for allowances can be affected by economic growth and financial markets as well. As the EU ETS is a politically constructed market, it behaves differently from other commodity markets. This demand and supply is influenced by a lot of factors which makes forecasting of demand and supply difficult.

Three examples of important factors are discussed below to show the CO_2 price uncertainty, which is the reason that the CO_2 price is a major risk for investment decisions. Further factors influencing the price of carbon will be discussed through the literature review.

- *Policy Uncertainty*

Although the EU ETS provides emissions targets till 2020, European electricity corporations remain dependent on international climate negotiations. The EU and the rest of the world witness an uncertainty concerning the future of a likely climate agreement. On one hand, the EU ETS needs a strong carbon price signal for legitimacy; on the other hand, European legislators know that if international agreements do not come to fruition, such a strong stance will cost Europe a lot in terms of competitiveness.

With the likelihood of a global deal on climate change policy most uncertain, a split and local approach to regulating carbon emissions is beginning to consolidate, with several economies implementing different emissions-control policies, which will ultimately impose different carbon costs on their industries.

In such a context, carbon leakage -or the carbon policy-driven migration of production (and emissions) to regions with less stringent or nil carbon constraints- has become a key policy concern. The problem is very real and is one of the main concerns for European lawmakers. If this happens in a large scale, the EU ETS will accomplish nothing to reduce emissions and will drive industry away from Europe (what has actually already started to happen in Germany, additionally due to the recently decided nuclear reactor phase-out),which possibly be the worst-case scenario.

- *Market Uncertainty: Fuel prices and demand*

As we already pointed out in section 2.4.3, fuel price is the major determinant of the variable costs of power production having an effect on which power plants are cheapest to run and this in turn affects the CO_2 emissions from the plants that are dispatched. For example low coal prices reduce the cost of coal production and increasing coal production increases CO_2 emissions. Also demand for CO_2 reduction in the future is uncertain.

- *Technological uncertainty:*

Technological development determines which technologies will be available to reduce CO_2 emissions. This in turn determines also the potential volume of reductions. It also determines the cost of abatement by learning effects. The development of technology in the future is hard to predict. Because it is depending on policy support and company effort in R&D

- *Market uncertainty*

Market uncertainty is related to policy uncertainty. Markets are good at pricing-in future expectations and the uncertainty over future climate policy affects the price of carbon. There are also other factors that contribute to market uncertainty which are due to the structure of emissions markets. A fundamental problem exists in the way that the carbon market adjusts to changes in supply and demand. A sudden change in supply, like what happened in April of 2006 very quickly led the carbon price to plummet. There is a fundamental problem in the inability of the market to adjust through the supply side. Since supply cannot adjust because there is a cap, the only way for the market to adjust is through price (Figure 4.1) which combined with the high uncertainty in the demand of allowances leads to wild price swings.

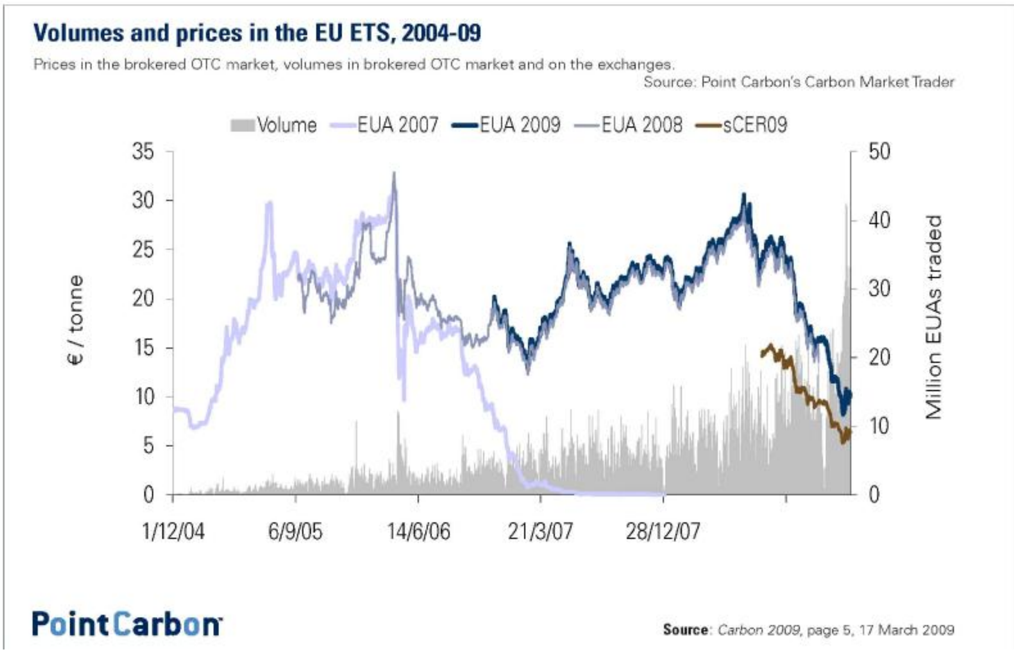

Figure 4.1: CO2 Allowance Price Volatility, source: Pointcarbon, 2009[31].

4.2 Literature review on carbon pricing mechanisms

Chevallier, 2011[32] provided a systematic update on the literature of carbon price mechanisms from 2007 onwards. It identified the relationships between the price of CO2 on the one hand, and its main fundamentals that allow to explain and forecast its variation overtime on the other hand.

4.2.1 The emissions shortfall factor

The best example of the influence of institutional decisions on the price development of carbon may be found during the year 2006. At that time Ellerman and Buchner, 2008[33] report that the first report of verified emissions published by the European Commission at the aggregated EU-wide level has had a dramatic impact on the carbon price, which fell by almost fifty percent in a few days. As afore mentioned, the main reason behind this structural change in the price of carbon was found in the ratio of allocated allowances to actual emissions: as all installations surrendered their quotas and sent their information to the regulator, it could be assessed for the first time that the carbon market was “over-allocated”.

4.2.2 Banking restrictions

An important effect of institutional decisions is the decision by the European Commission to ban the transfer of any banked or borrowed allowances from Phase I (2005-2007) to Phase II (2008-2012). Consequently, any allowances in surplus as of December 31, 2007 would be worthless on January 1, 2008. The main reason behind that decision may be that the European Commission did not want to transfer market design imperfections from the first test period of the scheme to the corresponding period of commitment of the Kyoto Protocol. Therefore, the banking instrument, which allows industrial operators to smooth emissions and to manage their stock of allowances, has been “sacrificed” in October 2006. From that date until the end of Phase I, two price signals have been coexisting:

CO_2 spot and futures prices December 2007 valid for phase I which were moving towards zero and CO_2 futures prices valid for phase II fluctuating in the range of twenty euros (with a perception of increased allowance scarcity during 2008-2012).

4.2.3 The influence of fuel (oil, gas, and coal) prices

Based on economic analysis (essentially demand and supply fundamentals), Christiansen et al., 2005[34] have identified the following factors as being the price determinants in the EU ETS: Policy and regulatory issues; market fundamentals, including the emissions-to-cap ratio, the role of fuel-switching, weather and production levels. Mansanet-Bataller et al., 2007[35] and Alberola et al., 2008a [36] were the first to report econometrically the relations between energy markets and the CO_2 price. Based on phase I spot and futures data, the former group of authors determined that carbon prices in the EU ETS are linked to fossil fuel (*e.g.*, oil, gas, coal) use. By using an extended dataset, the latter group of authors emphasize that the nature of this relationship between energy and carbon prices varies depending on the period under consideration and the major influence of institutional events

4.2.4 Power producers' fuel-switching behavior

The demand for fossil fuels depends on their absolute as well as relative prices. From that perspective, the marginal fuel-switching costs from highly carbon-intensive sources of energy (such as coal) to lower carbon-intensive sources for power and heat generation (such as gas) constitute another important determinant of the CO_2 price.

As a general rule-of-thumb, carbon abatement in the short-run heavily depends on the behavior of power and heat operators, who are the main actors under the EU ETS. Moreover, emissions abatement costs from the power sector are assumed to be the lowest compared to other sectors, based on fuel-switching from coal to gas. Among other contributions, Delarue and D'haeseleer, 2007[37], Alberola et al., 2008a [38], and Keppler and Mansanet-Bataller, 2010[39] separately studied these causalities between CO2 and electricity variables (such as clean dark and clean spark spreads, and the switch price) during the first phases of the EU ETS.

4.2.5 The role played by temperatures and extreme weather events

As documented by Mansanet-Bataller et al., 2007[35] and Alberola et al., 2008 [38], CO2 prices are also affected by unexpected climatic variations. For instance, cold winters (hot summers) increase the need for heating (cooling) by using electricity. Alberola et al., 2008 [38] show that extreme and unanticipated temperature events have a statistically significant effect on carbon price changes. Furthermore, rainfalls, wind speed and hours of sunshine directly affect the share of power generated by carbon-free heat generation from hydropower, wind and solar energy. Taken together, these factors may contribute to explain why the weather is widely acknowledged to play an important role in shaping the price of carbon.

4.2.6 Macroeconomic and financial market shocks

Based on the characteristics of the global economic context and changes in industrial production in EU ETS sectors during 2005-2007, Alberola et al.,2008b, 2009[40] provide the first econometric exercises deriving the correlation between production and environmental conditions on carbon prices. As industrial production increases, associated CO_2 emissions increase, and therefore more CO_2 allowances are needed by operators to cover their emissions.

More recently, Declercq et al., 2011[41] investigate the impact of the economic recession on CO_2 emissions in the European power sector during the years 2008 and 2009,with their simulations demonstrating that an emissions reduction of about 150 million tons may be expected from the European power sector during the period as a consequence of the recession.

4.2.7 Macroeconomic indicators

Interestingly, several studies uncover some econometric links between the carbon market and several indicators related to macroeconomic and financial markets. Oberndorfer, 2009[42] has first tackled this issue from the angle of the stock markets. The author shows that CO_2 price changes and stock returns of the most important European electricity corporations are positively related, with this effect being particularly strong for the period of carbon market shock in early 2006. Next follows a review of the evolution of the carbon price since the implementation of the EU ETS in 2005.

4.3 Historical evolution of Carbon prices

In the first phase of the ETS (2005–2007), the prices of tradable CO_2 emission credits were highly volatile. In retrospect, this was due to the limited time horizon of this phase, the highly politicized process for determining the emission cap, uncertainties regarding the cost and availability of abatement options, the mismatch between the actual and forecast demand for emission rights, and the inelasticity of the supply of emission rights.

As mentioned above, in April 2006 the CO_2 prices collapsed, firstly because of the grandfathering of EU-ETS emission rights and secondly because the emissions cap in Phase I (2005-07) was not strict enough to avoid the over-allocation of allowances. However, as analysts expected a shortage at the beginning of the phase and forward prices soared to nearly €30/t in 2006 ‘‘*on the back of the European Commission tightening the proposed National Allocation Plans, high summer temperatures and increasing energy prices*’’ (Wagner, 2009[43]). As soon as the economic crisis began, Phase II allowance prices plummeted from a high of about €30/t in July 2008 to €8/t in February 2009, but with expectations for recovery of the EU economy, EUA prices reached €13/t by mid June 2009. (Wagner, 2009[43]).

Since then carbon prices moved sideways till June the 10th, 2011 with the December carbon contract for next-year delivery of EUA allowances which had risen by about 3 €/t through the end of March on increased power generation from natural gas and coal, due to Germany's nuclear moratorium, subsequently trended downward ending June with the a free fall of reaching its lowest point in August the 8th, 2011 of 10,63 €/t in driven by sovereign debt problems, slow recovery from recession and climate policy uncertainty combined with low demand for EUA emissions permits (raising doubts about the viability of more ambitious targets).

It's not hard to see why analysts see little optimism for any short term recovery in the prices of EUAs or CERs. Key to the longer term price outlook is whether the EU decides to lift its 2020 emissions reduction target from 20 per cent below 1990 levels to 25 per cent, thus obliging emitters to cut further.

But if the target stays at 20 per cent, prices are forecast to remain in the current range of €10 to €15, unless a new recession pushes prices off the cliff.

CHAPTER 5

ECONOMICS OF POWER PLANT INVESTMENTS

5.1 Introduction

We previously discussed the theory and application of emissions trading as a regulatory mechanism, focusing on how it provides incentives for a change in economic behavior. The subject of discussion in this chapter will be presenting the economic impacts of the EU ETS on electricity producers in order to highlight the multitude of interrelated factors that will shape an investment decision.

And this will take place by discussing the effects of carbon policy and consequently of carbon price on the operational decisions of a power generator. In our opinion, understanding these effects, which have direct impacts on the short-term profitability of PGs, are essential in order to further understand the impact of CO2 price on long term investment strategy.

First we will discuss about the economic surcharge for power generators caused by the introduction of the EU ETS. Next we will investigate the effect of carbon price on the cost of power production and electricity price, including wholesale prices and retail prices and windfall profits. After that we will discuss the effect of carbon price on the power generator's windfall profits and finally we will see how carbon prices influence short-term power plant operational strategies such as fuel switching.

5.2 CO_2 price economic impact on Power Generators

5.2.1 Introduction

The full extent of the economic impacts caused by emissions trading on power generator is enormous. These impacts affect everything from dispatch order of power plants to interest rates. The impact on the power sector takes place at two levels. Firstly, the carbon price has been introduced in operational decisions. Anytime a ton of carbon is emitted in the production process, the operator compares the corresponding profit margin for the production with the opportunity cost of selling the allowance on the market. Secondly, the carbon price can be factored in longer term decision making - namely the decision to invest in several abatement solutions. Should the carbon price be high enough, decision-makers might consider it more advantageous to invest in carbon-free or less carbon-intensive production technology. The main economic impacts of the CO_2 price on power generators will be presented in the following.

5.2.2 The effect of CO_2 price through trading of Allowance Expenses

To start with, the introduction of the EU ETS has created a new commodity that needs to be managed and traded by generating stations. There are costs associated with trading commodities (such as the costs of additional personnel/training, IT/communications, broker's fees and market information).

Actually the most straightforward type of impact from the CO_2 price creation is the impact from direct costs resulting from the company's need to buy allowances which results expenses. These costs of covering carbon emissions definitely influences future investment decisions and generation technology choices. Most companies already reflect the allowance cost in their daily operations and the evaluation of future investment decisions (PriceWaterhouseCoopers, 2005[44]).

Figure 5.1 shows the imbalance between supply and demand by sectors in the EU-ETS between 2005 and 2006. Almost all the demand for allowances to cover emissions comes from the power and heat sector (concerning practically electricity generators). So most electricity producers in Europe were short permits between 2005 and 2006.

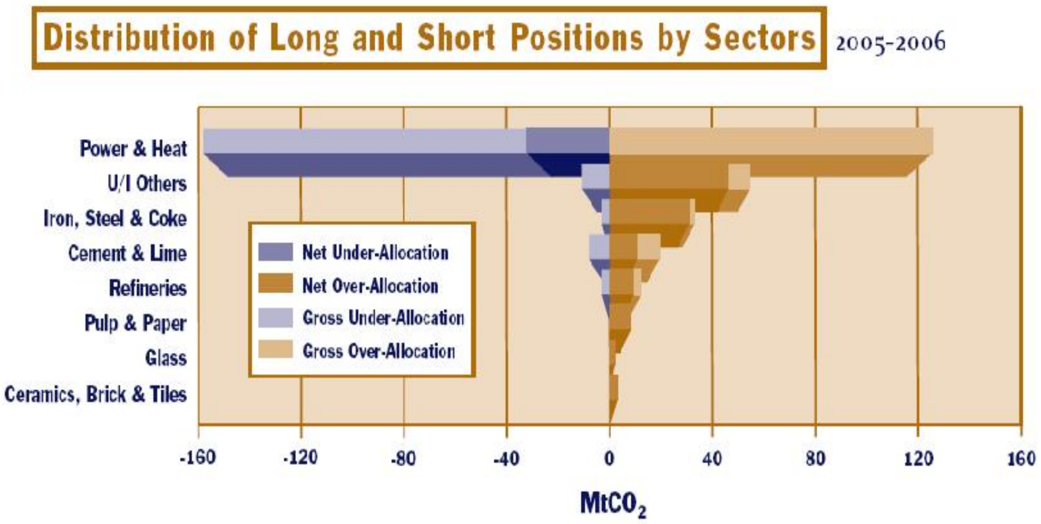

Figure 5.1: source, deBruyn, S.M., 2010 [26] .

Although electricity producers in Europe receive each year of the Phase II EU-ETS period a free initial allocation of allowances, most of them need to procure each year additionally vast number of permits. This results, even with conservative estimations based on present EUA price levels huge expenditures which need to be covered. German electricity utility RWE, reported that for each one of the years in Phase II EU-ETS period the company is currently 60 to 70 billion EUA's short which need to be purchased in the market. These expenditures will skyrocket in Phase III EU-ETS period when the free allocations period will end with the amount of EUA's for RWE soaring to about 160 and 170 billion, affecting accordingly the operating results of the company (Figure 5.2).

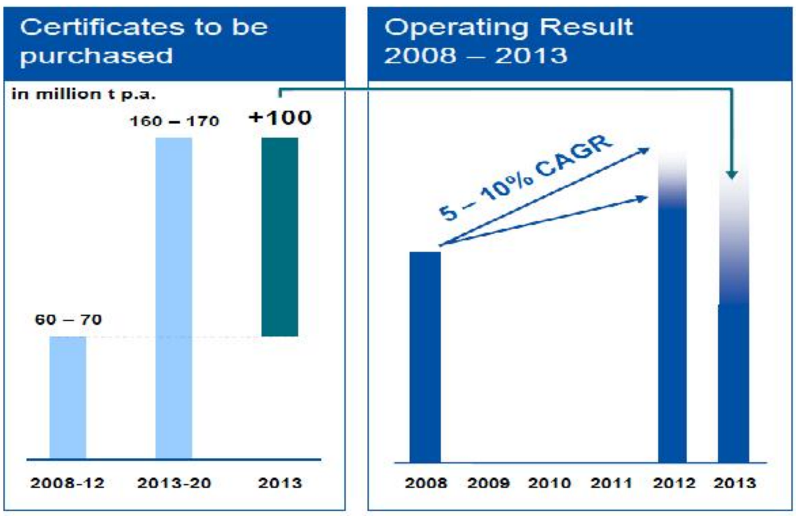

Figure 5.2: source RWE, 2010[15]

We cannot make any conclusions on the effects of the EU ETS on investments by looking solely at permit expenses. While these do provide a signal to reduce emissions that is in line with economic theory, there are other factors at work. We must therefore contemplate the electricity market as a whole to understand how it functions and how it interplays with emissions markets in order to provide incentives for abatement.

Furthermore, permit trading can bring in also profit opportunities for a power generator by being a physical player in a commodity market. It is likely that the large vertically integrated generators are those most able to benefit from the opportunities of trading, and their additional costs will be low in relation to their total fixed costs. Independent generators will face higher costs in relation to their total fixed costs, and may be relatively risk averse in terms of actively trading in carbon markets.

Finally there is a number of additional costs that generators will face as a result of the introduction of the EU ETS and the carbon price. These include monitoring and verification of emissions costs and costs spent for hiring additional personnel which is needed due to creation by the EU ETS of an additional level of regulation.

5.2.3 The effect of CO_2 price on power plant dispatch and merit order

In a liberalized marketplace, due to low price elasticity of demand, prices are driven by the merit order structure. The merit order method relies on a priority list that ranks the generating units in some order of preference. With this technique a list is being generated to rank all units according their short run marginal costs. Typically, at the bottom of the merit order are plants with high fixed costs and low variable cost. At the top, plants with high variable costs and low fixed cost. In most European countries the cheapest and most efficient generators are used to generate base load which usually are nuclear, hydro, wind and the most efficient CCGTs. Midload is generally met by coal or gas generators and peak load may require the most expensive OCGT (Figure 5.3)

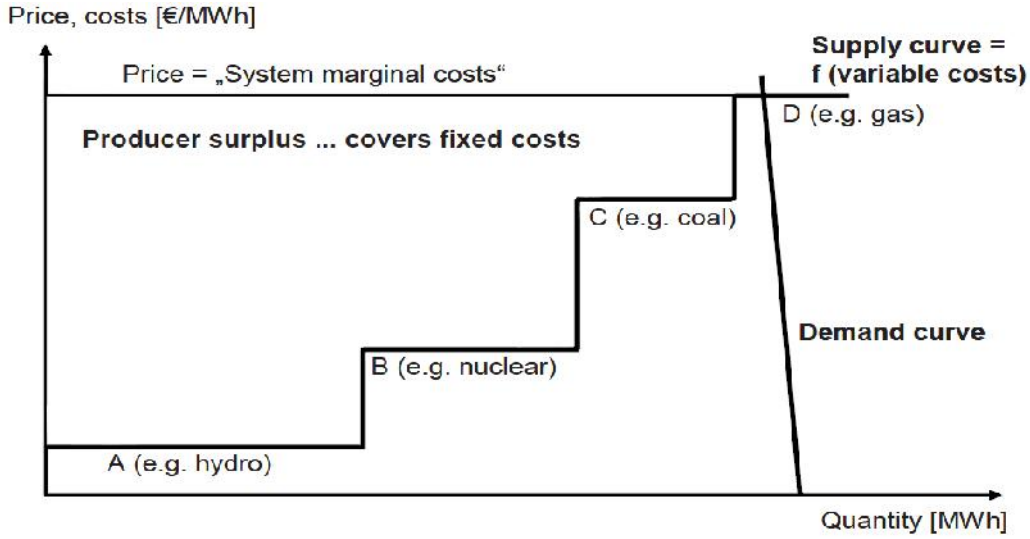

Figure 5.3: Price formation in electricity markets, Handbook Utility Management, 2009[47]

The price of electricity is set through a single clearing-price auction. The market operator forms total demand and supply curves and clears the market at the market clearing price through a supply and demand equilibrium (Figure 5.3). When a plant is at the ‘’margin’’, the market price of electricity is equal to its short-run marginal costs. (the marginal plant). Plants that are above this level do not operate and plants below are able to make a marginal profit.

In a non-carbon constrained environment the SRMC of each plant is a function of short-run non-fuel variable costs (operational and maintenance costs, the cost of fuel and the generating unit’s efficiency which also determines the merit order). At any given time therefore, the price of electricity covers the SRMC of the most expensive generator. The same logic applies in a carbon-constrained environment, except that the cost of carbon is built into the cost of generation for each thermal generator. A carbon price may mean changes to the merit order as different generation technologies and fuels emit different volumes of CO_2 for each unit of electricity dispatched, for example conventional coal stations emits nearly twice as much CO_2 as combined cycle natural gas units.

Figure 5.4 shows how the introduction of a carbon price changes the merit order of generating assets while reducing the gap in the merit order between upper base-load and lower peak-load electricity : the nuclear plant which has no CO_2 emissions is the cheapest of all units and is first in the merit order. Furthermore the existence of a carbon price adds more to the marginal cost of coal generation than it does to gas, making gas which burns more cleanly the cheaper generation technology.

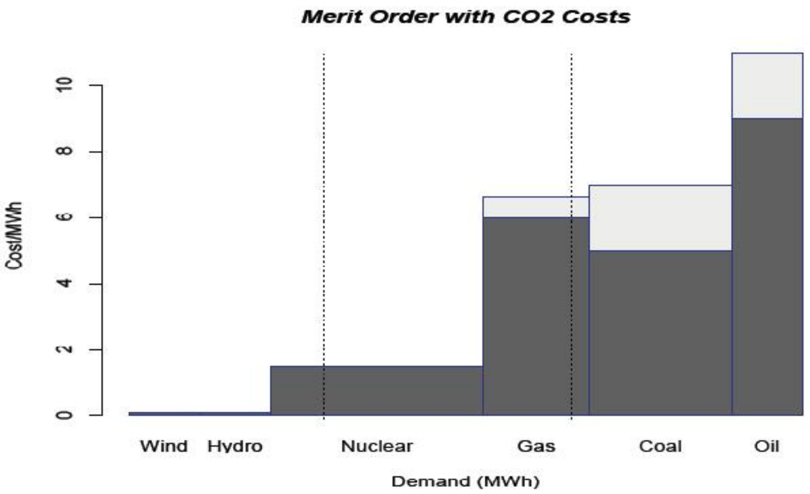

Figure 5.4: The impact of the merit order in CO_2 price pass-through to electricity price Source:(Carmona,R. [46]).

Furthermore, Figure 5.5 shows a case scenario explaining the different short-run marginal costs (SRMC) of coal and gas generation. In this case, due to higher marginal costs of natural gas compared to coal, natural gas is at the margin and sets the short-run price of electricity. As the price of CO_2 increases, the SRMC for gas and coal increases. However, the SRMC of coal increases at a faster rate due to carbon emissions that are approximately double those of natural gas. In between 20-30$ per ton of CO_2, coal generation moves to the margin and begins to determine the price of electricity. It also quite clear that at this threshold, the slope of the marginal price of electricity changes and becomes more sensitive to changes in CO_2 price.

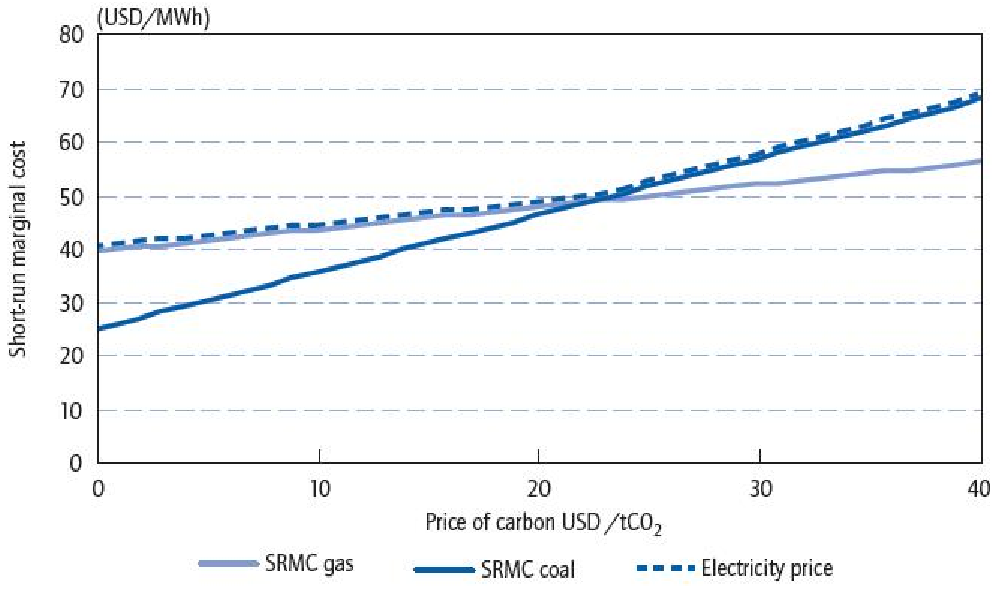

Figure 5.5: The impact of the merit order in CO_2 price pass-through to electricity price source, (Blyth et al., 2007 [28]).

5.2.4 The effect of CO_2 price on the electricity price

One of the key elements of a cap-and-trade-system is that for an electricity generator holding emission allowances, the production of carbon emitting power competes with the possibility to exchange the unused allowances. This is called opportunity cost of the EUA's, has equal value with the CO_2 market price and is therefore being incorporated in electricity generators' decisions.

Several factors influence the degree that the opportunity cost of the so far free allocated emissions allowances is reflected in the end user electricity prices .These could be the regulatory frameworks, the elasticity of demand, the agreements between suppliers and end-users and finally the EUA allocation rules of different governments.

Nevertheless, the economic background of a cap-and-trade system is that the carbon emissions price should be reflected in the end user prices in order to encourage cleaner electricity generation through higher expected profitability.

There are three obvious reasons why it is difficult to figure out safely how the EU ETS has affected so far electricity prices. Firstly there is no united European Union electricity market, but a fragmented market regulated by different frameworks. Secondly, there are additional factors which equally affect generation prices such as volatility of natural gas prices or the use of market power by power utilities. Thirdly, no data can be collected concerning the bidding strategies and the marginal plant supplier to the market, making it extremely difficult to determine the level of pass-through of CO_2 prices in electricity prices.

There are some empirical studies researching the impact of EU ETS on power prices, an overview list is shown in Table 5.1:

Table 5.1: Summary of empirical studies on impact of EU ETS on power prices (source Sijm, J., 2007, [49]).

Study	Country	Market	Period	PTR (%)
Bauer and Zink (2005)	DE	Forward	Jan-June 2005	100
Bunn and Fezzi (2007)	UK	Spot	2005	42
Chernyavs'ka and Gulli (2007)	IT	Spot	2005 2006	0 -50 to 200
FE (2006)	NL	Forward	2005	4 to 108
Honkatukia et al (2006)	Finland	Spot	Feb. 05 - May 2006	75 to 95
Levy (2005)	FR, DE, IT, ES, UK	Spot	Jan-June 2005	-180 to 220
Riechmann et al (2006)	UK, NL, Scandinav.	Forward	2005	89-98
Sijm et al. (2005, 2006a and 2006b)	DE, NL DE	Forward Spot	2005 2005	39-117 50-250

The major findings of the above empirical studies have been:

1. A significant pass-through of carbon costs to power prices was confirmed for:
   - Forward markets (2005) concerning Germany, the Netherlands, the UK, and Scandinavian countries
   - Spot markets: Italy (2006) and Finland (2005-2006)

2. Empirical estimates of pass-through rates vary widely depending on:
   - Country concerned
   - Markets analyzed (spot/forward; peak/off-peak)
   - Period considered
   - Data used
   - Assumptions and estimation method applied

5.2.5 The effect of CO_2 price on the wholesale electricity prices

A study with empirical analyses of the trends on power, fuel and carbon markets for nine major EU ETS countries came to the following findings Sijm et.al.,2008 [50]. In general, forward power prices in the countries analyzed have increased significantly between early 2005 and mid-2006, in particular for peak products.

In Germany, electricity prices increased strongly along with carbon prices since the introduction of the EU ETS in 2005, VIK, 2006[51] as cited in Reinaud, 2007[52]. The significant increases in forward power prices in 2005 can be largely attributed to higher fuel prices in those cases where gas-fired plants set the price, and to a lesser extent to the pass-through of carbon costs. On the other hand, in those cases where coal-fired stations determine the price, increases in this price can be mainly attributed to the pass-through of carbon costs (and hardly to higher fuel prices as the price of coal has hardly increased in 2005).

On the spot markets, it is more difficult to find a clear correlation between changes in the power prices on the one hand and changes in the fuel and/or carbon costs on the other hand, mainly due to the incidence of other factors affecting the power price on these markets, such as extreme or rapidly changing weather patterns, plant outages or other factors causing major fluctuations in market scarcity in the short term. Sijm et.al(2008).

Over a relatively short period, which applies particularly for the period March-mid July 2005, when CO_2 prices on the EU ETS market increased steadily from about 10 to 30 €/tCO2 (with a correlation of 0.98) and in April-May 2006, when CO_2 prices collapsed suddenly from approximately 30 to 10-15 €/t CO_2, the link between CO_2 prices and power prices is occasionally very clear. Between July and December 2005, the carbon market had a sideways trend and the correlation was less distinct.

The low correlation between CO_2 prices and power prices between July and December 2005 (Fig 5.6) and more generally over longer time periods implies that the relationship between carbon and power prices is less clear, most likely because over longer time periods power prices are affected by other factors besides fuel and carbon costs, such as changes in market structure or generation capacities (Sijm et.al, 2008[50]).

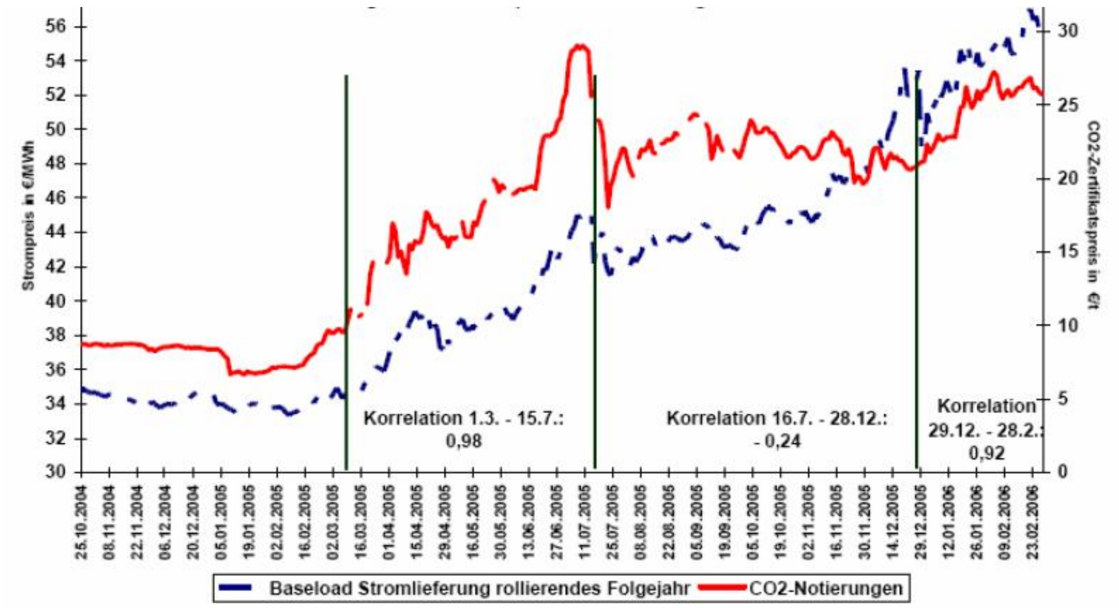

Figure 5.6: Correlation between Base-load Electricity Prices and CO_2 Allowance Prices in Germany, source: VIK 2006[51].

Moreover, after the collapse of the carbon price in April/May 2006 and, particularly, during the latter part of 2006 (when both carbon and gas prices declined steadily), the correlation between power prices and fuel/carbon costs is obviously r less clear implying that other factors - such as growing capacity shortages or market power - have become more important in affecting power prices.

The effects of the drop in CO_2 prices on the day-ahead prices in May 2006 clearly demonstrate the reality of the pass-through. Carbon prices dropped by more than 50 percent mid-May2006 upon reports that the Czech Republic, Estonia, France, the Netherlands and the Walloon region emitted far less CO_2 in 2005 than initially anticipated by the market (Figure 5.7). Consequently, power prices on the European market exchanges dropped. A €10/t fall in the price of EU allowances was immediately followed by a drop in electricity prices of at least 5-10 €/MWh in Europe (PointCarbon, 2009[31]).

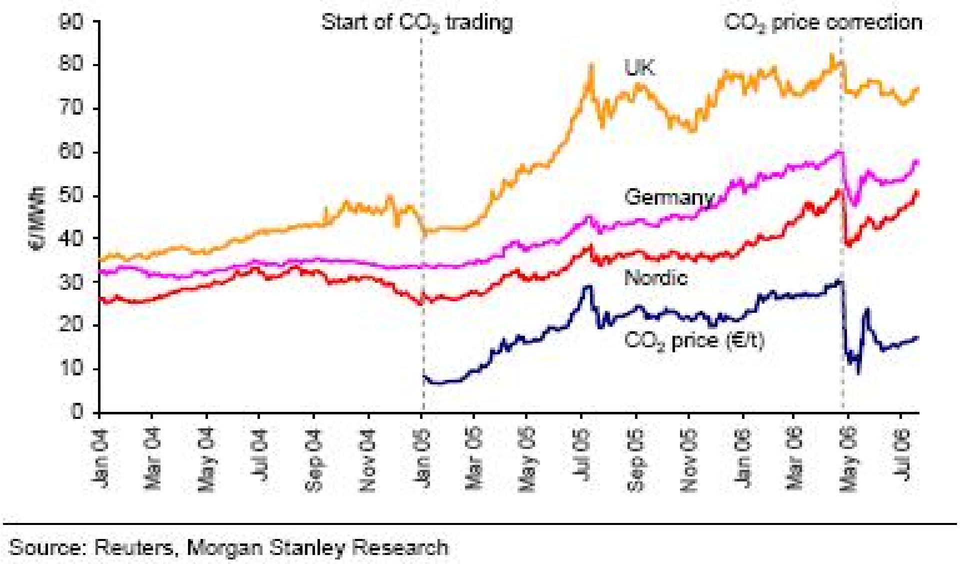

Figure 5.7: Electricity and CO_2 Prices between January 2004 and July 2006, source: Reinaud, 2007[52].

5.2.6 The effect of CO_2 price on the electricity retail prices

Sijm et.al,2008 [50] states that power prices on retail markets in EU ETS countries have increased significantly over 2004-2006. If it is assumed that over the period 2004-2006 changes in the retail power spreads - defined as retail power prices excluding taxes and fuel costs - are only due to carbon costs passed through, the impact of the EU ETS on retail power prices was still relatively low in 2005 due to relatively low year-ahead carbon prices in 2004 and, perhaps, some constraints in passing through these costs to retail prices.

Moreover, if it is assumed that the carbon costs passed through on the retail market are similar to the carbon costs passed through on the wholesale market, the impact of these costs - and, consequently, of the EU ETS - on retail power prices becomes generally even more significant. Wagner R., 2009[43] argues that rising energy prices showed after the imposed deregulation as expected the way up to the r household power prices and as can be derived from Figure 5.8, the introduction of the EU ETS just led to a continuation of the trend to higher retail prices but not to acceleration.

Both agree that retail prices are only influenced to a minor extent by CO_2-prices with household prices being more dependent on other cost components than the power generation costs including high energy taxes and high distribution or other marketing costs which mainly determine retail power prices.

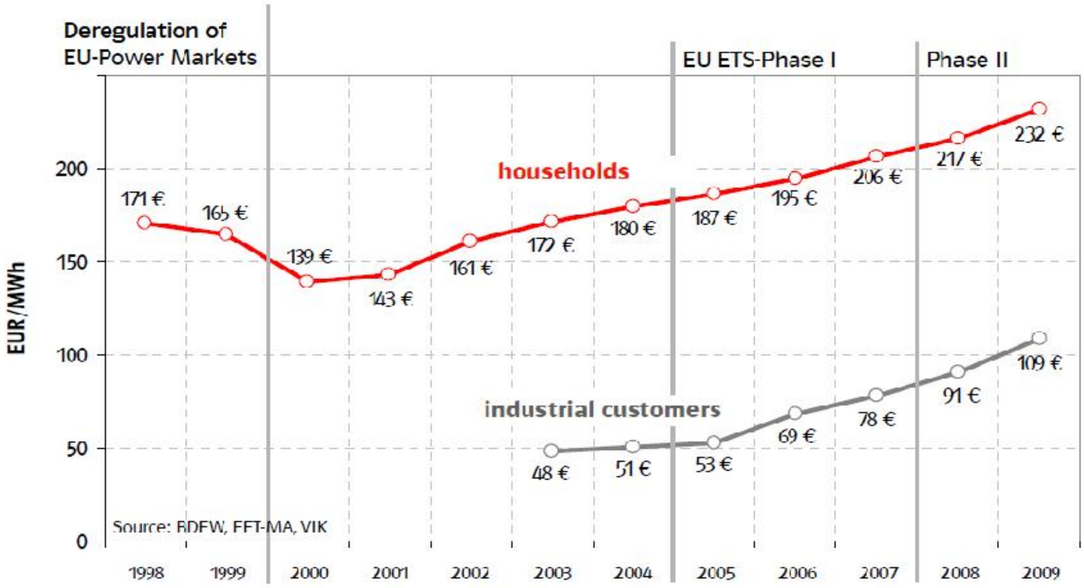

Figure 5.8: Retail electricity prices in EU, source: Wagner, R., 2009[43].

5.2.7 CO_2 price and Cost Pass-through to Consumers

As supported by economic theory and empirical evidence, power producers in competitive electricity markets pass through (part of) the opportunity cost of CO_2 emissions trading, even if they receive carbon allowances for free. This is known as the pass-through rate. Sijm et.al, 2006[27] state that from a climate policy perspective, passing through the costs of CO2 emissions is a rational and intended effect, enhancing the efficiency of emissions trading by giving incentives to end-users to reduce their consumption of carbon intensive goods.

Sijm et.al, 2006[27] further distinguish between the behavior of individual electricity producers and the market as a whole in what they call "add-on" and "work-on" rates. The add-on rate is the margin that is added to marginal bids in order to cover additional carbon costs. In a liberalized market, the market works through a single clearing-price auction and generation companies can accomplish the full pass-through of marginal costs. In a regulated market, companies are only able to pass additional carbon costs to the degree allowed by the regulator. Sijm et.al, 2006[27] estimated that the average pass-through rates varied from 40 percent to 70 percent depending on the country and whether it was a peak or off-peak demand period. The work-on rate is the result of effects in the market due to demand-response. Sijm et.al, 2006[27] found that electric producers absorbed a part of additional carbon costs when elasticity was high (Sijm et.al, 2006[27]). Whatever the effect of CO_2

costs on wholesale electricity prices, the effect on retail customers depends on the degree of liberalization in retail markets.

5.2.8 CO_2 price and the issue of windfall profits

Intense public criticism has been caused from the issue of "windfall profits" which refers to the higher electricity prices and consequent higher corporate profits that resulted from the fact that freely obtained allowances were passed through in prices, especially in peak prices instead of investing to innovation to provide clean, renewable energy. (Figure 5.9). As it was shown in a liberalized market under free allocation, companies tend to pass carbon costs to consumers even if they were receiving them for free (Sijm et.al, 2006[27]).

European power companies will gain an additional 23-63 billion euro in windfall profits between 2008 and 2012 with the highest levels of windfall profits for Germany and UK due to the high level of pass-through as well as the relatively high level of emission intensity of marginal plant. (Point Carbon, 2008b [53]).

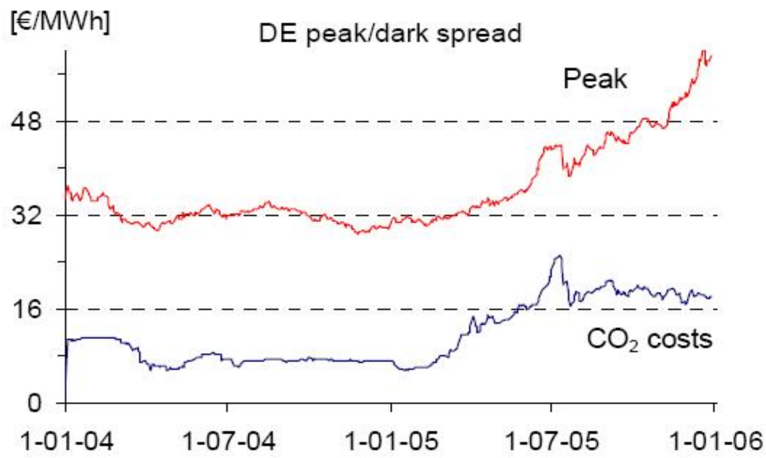

Figure 5.9: Windfall profits in electricity sector, source deBruyn, S.M., 2010, CE Delft, 2010 [26].

Freely allocated allowances will have a very different effect on electricity prices depending on the degree of liberalization in each member country. Whether an electricity generator in a competitive market has received the allowances for free or not, the relevant consideration in participating in the electricity market is the opportunity cost of using the allowance to cover emissions. Since every allowance used to cover emissions means the loss of the opportunity to sell that allowance. an opportunity cost is incurred and that cost which is reflected in the marginal price of electricity. Whether allowances are distributed for free or through an auction will typically have no effect on market prices in competitive electricity markets, although it will affect individual supplier profitability, Ellerman, Joskow, 2008[54]).

Starting in 2013, the electricity sector will move to full auctioning. Auctions will change the availability of current and future allowances in the market, affecting carbon prices. The trend towards further liberalization is likely to continue to the extent that most European markets are likely to be sufficiently competitive by 2013 to allow wholesale electricity prices to be determined on a short run marginal cost basis incorporating the full cost of carbon allowances. Even in a scenario where existing, partly liberalized regulatory and pricing frameworks are maintained to 2013 a switch from free allocation of allowances to full auctioning would have a small impact (New Carbon Finance, 2008[55]). Furthermore, auctioning would ensure that carbon prices are passed through into retail prices where electricity markets have not been liberalized and it would raise substantial revenue for the government that could be used for other purposes some of which could improve efficiency.

In a liberalized market under free allocation, companies have shown to pass carbon costs to consumers even if they were receiving them for free (windfall profits) (Sijm et.al, 2006[27]). This is because there is an opportunity cost in generating electricity. Companies have a stock of allowances for which they have the option of selling in the market. By generating electricity, they are forgoing this opportunity. Carbon permits are added to the marginal price of electricity to take this into account, even if they receive them for free. Because of this, European power companies will gain an additional 23-71 billion euro in windfall profits between 2008 and 2012 (Point Carbon, 2008b [53]).

The electricity sector will move to full auctioning as soon as Phase III sets off.. Auctions will change the availability of current and future allowances in the market, definitely affecting carbon prices. The structure of auctioning systems is still to be determined by the individual countries.

5.3 The effect of CO_2 price on the generation composition portfolio

The composition of generating portfolios will determine the exposure of utilities to market fluctuations. Firms can be hedged by diversifying their generating portfolio to the point where market risk is equal to that of a market portfolio representing the general economy. Plants have technology-specific risks due to the price risk from fuel and carbon market. There are also risks from changes in the merit order which affect the ability of individual plants to pass carbon costs onto electricity prices.

The exposure of a firm's generating portfolio to the carbon market can be obtained by calculating plant emissions relative to the market in which the firm participates.

5.4 Short-Term CO_2 Abatement in the power sector

In the context of this chapter assessing the economic impacts of carbon price on the operational decisions of power generators, we will discuss in this section about the short-term carbon abatement choices such companies have at their disposal while optimizing their cash-flows, although short-term switching conditions do not actually refer to new investments but only consider shifts in plant utilization. We will come back to discuss these options by introducing the factor of timing and postponement of power plant investment decisions using the real options approach in chapter 7.6.3.

As pre-mentioned in section 2.3. emissions reductions in the power sector can be achieved by means of short-term operational adjustments (like fuel switching to a lower carbon content combustion fuel), investments in less carbon-emitting technologies (retrofitting power plants with carbon capture and storage or closure of power plants running on high polluting fuels and investing in a plant that emit less like renewable energy, gas or nuclear power, or by decreasing the power plant (and consequently the emissions) output.

The choice to switch fuels has been a predominant short-term strategy for power producers. The spark and dark spread is the most important determinant factor in the choice to switch fuels. Switching can be accomplished at the individual plant level, company level and sector level. For individual companies, the choice to switch is made on a cost-basis and changes day-to-day and hour-to-hour according to the dark and spark spreads. In order to have a better assessment of the potential impact of CO_2 emissions trading on forward power prices, fuel costs have been subtracted from these prices, resulting in the so-called 'power spreads.

The spread is the theoretical gross margin of a power plant selling one unit of electricity and buying fuel at a certain price. It is calculated by taking the price of electricity and subtracting the cost of fuel multiplied by the heat rate needed to produce one unit of power. The spark spread is given by:

Spark Spread = Price of Electricity - [(Cost of Gas) x (HeatRate)]

Equation 5.1: Spark spread

Spark spreads are a measure of the profitability of gas plants, while dark spreads show the profitability of coal plants. When there are tight spreads in the market, only the most efficient plants will be dispatched. When the cost of carbon allowances is included, these are referred to as the “clean" dark and spark spreads.

Spark spread can also be used to assess the loss of revenue if a power station is switched from a normal running scenario to one where it is held in reserve to provide power when a large number of renewable generators, is unable to generate. In such a case the power station operator would be indifferent to such non-running as long as he was paid the spread it would have earned otherwise. When the cost of carbon allowances is included in the calculations, these are referred to as the clean dark and clean spark spreads.

The figures 5.10 and 5.11 below show how the “clean” spark and dark spreads affected gas and coal generation in the summer of 2007.

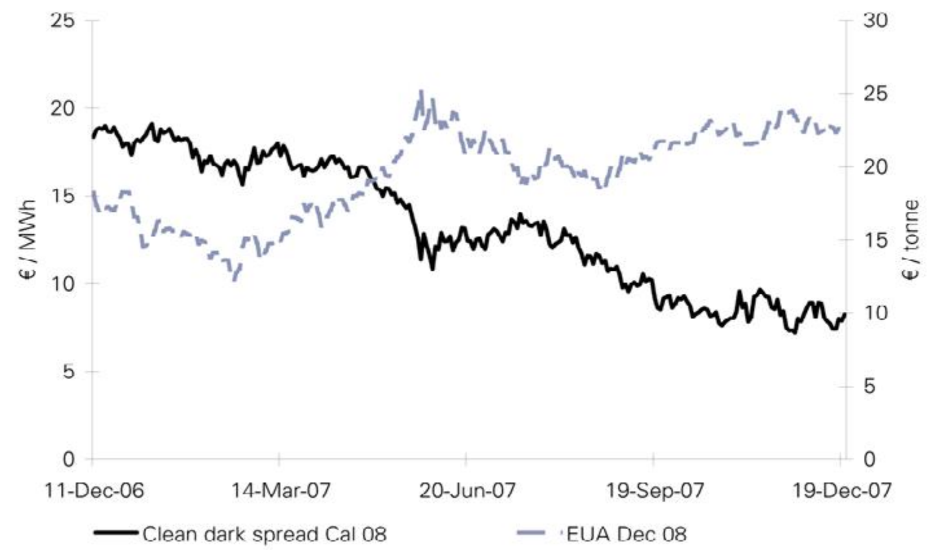

Figure 5.10: The inverse relationship between European Union Allowances (EUA) and coal profits is evident. Increases in EUA prices in the summer of 2007 were enough to sink the profits of coal producers by approximately one third (Point Carbon, 2008a[56]).

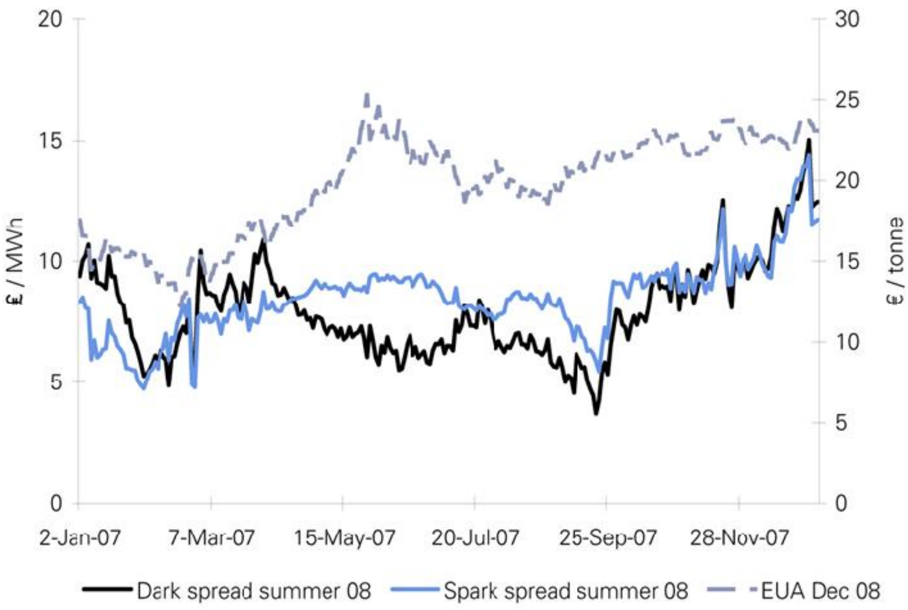

Figure 5.11: The sustained increase in the EUA price after April of 2007 raised the profitability of gas-fired generators above coal for a large part of the year (PointCarbon, 2008a[56]).

5.4.1 Fuel Switching price

For a coal-fired and a gas-fired plant with given dark spread and spark spread respectively, the calculated CO_2 value which is necessary to switch these plants in the merit order, is called the switching point (Sijm et al. 2005[57]). This reflects the value that would equalize the profitability of a gas fired power production and a coal fired power production. The formula for calculating the switching price is the following:

$$Switching\ price = \frac{\frac{P_{coal}}{\rho_{coal}} - \frac{P_{gas}}{\rho_{gas}}}{E_{gas} - E_{coal}}$$

Equation 5.2: Switching price

where, ρ represents the thermal efficiency of a power plant and E the emissions and is given in terms of tons of CO_2 emitted per MWh of electricity produced.

The switching price is fundamental in carbon credit pricing because the marginal cost of a credit should in theory follow the switching price.

The first condition in order to pursue fuel switching derives from an economic point of view. More specifically, by switching from coal to gas, a power generator will need to acquire less allowances or eventually be able to sell a percentage of them.

A second condition for switching concerns the technical potential of a power generator. With the increase of carbon prices, power generators are endangered with facing negative clean dark spreads and will be forced to switch fuel ,assuming obviously either that they have the capacity to switch or that they have both types of generation plants in their portfolio. Obermayer, 2010[58] analysed data series and calculated switching prices meeting the conclusion that the switching price is a quite poor indicator of the EUA price.

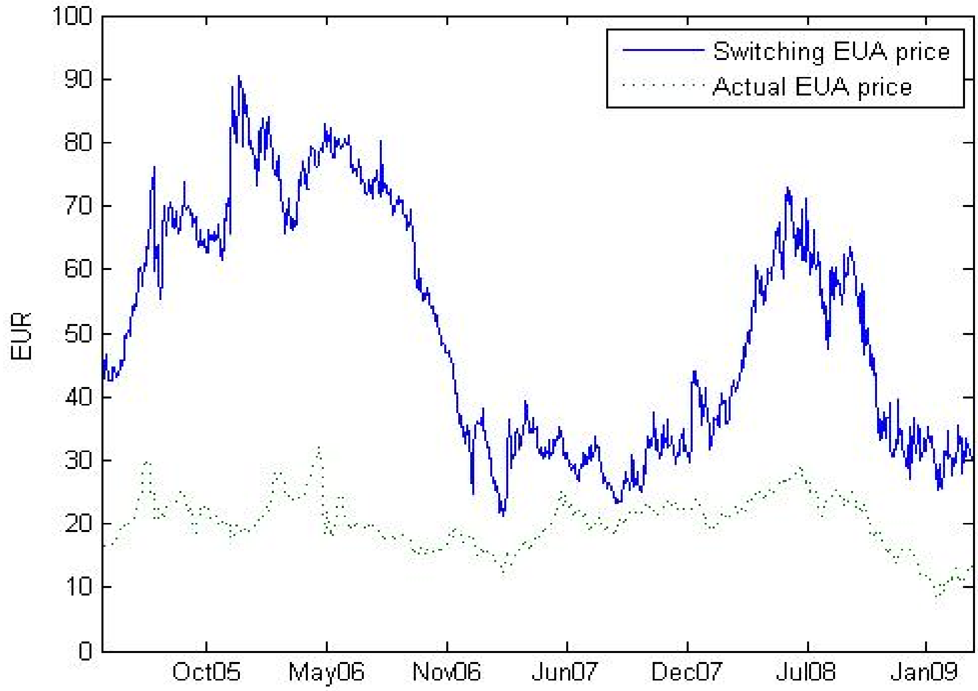

Figure 5.12: Implicit EUA switch price necessary for fuel switching from coal to gas-fired power generation. (Source: Obermayer,, 2010[58]).

With different data sets and sources, this plot will look a little bit different. In any case, we see that switching price is of little help in determining a fundamental value of EUAs. EUA carbon credits must therefore be seen as an independent asset class, and are not priced according to the fundamentals theory. Another observation is that EUA prices are relatively stable compared with the actuating switching price. One reason for this is that switching price is a too much simple model for interpreting such a complex market as carbon credits.

There are many more market forces at play which can severely impact price, than those presented in this model.

Delarue et al.,2008[59] came to similar conclusions : He documented via modeling that the decision of whether the utilization of any new plant via fuel switching will warrant the investment given expected fuel and CO_2 prices over the lifespan of the intended investment must take into account the highly complex relationships between load, fuel and EUA prices. There is no single constant relationship between the price of CO_2 and abatement but for any given hour with given load and fuel prices, the expected rising relationship between price and abatement can be observed. However, as soon as we move long-term (days, weeks, years), the constancy of the relationship is not valid anymore. Thus, the quantity of abatement from fuel switching that will be obtained for given prices of CO_2 are heavily dependent on the actual hourly load, which varies significantly over daily, weekly, and seasonal cycles, and on the relative price of natural gas and coal, which varies on a daily basis.

5.5 Conclusion

This chapter shows how the EU ETS affects the operations and earnings of power generators. The impact of the EU ETS is felt in many different parts of the business although the existence of a carbon price does not guarantee that abatement will take place. There are other factors in the market which will change the ultimate impact of emissions trading. E.g., the merit order and the aspects influencing its structure provide a better tool for looking at the dynamics of power plant portfolios. The technology that is at the margin sets the marginal price and thus is able to pass any additional costs to the electricity price. As the price of electricity increases, coal power plants could move to the margin which would have the effect of increasing the sensitivity of the electricity to the CO_2 price and shift the full cost of CO_2 permits to consumers.

Another factor that was discussed was the regulatory structure of the market. In a liberalized market, there will be a greater degree of freedom to pass additional costs to consumers. This has already been observed in markets like Germany, where the electricity price has become strongly correlated with the price of CO_2.

The risks that the carbon market brings in to electricity producers cannot be ignored. There is a range of factors that producers take into consideration outside of the cost mechanism.

CHAPTER 6

DIFFERENT APPROACHES TO SIMULATE FUEL, CARBON AND ELECTRICITY PRICES

6.1 Introduction

The most important uncertainties concerning power plant investments have to do with the future contribution margins issued by new power plants which for the most part depend on the future values of fuel, carbon and electricity prices. Such forward prices of gas, coal and electricity are practically available only for a period of 36 months , which is the reason that utilities are forced to make assumptions of the future development of the market price. Furthermore, market participants are aware that it is unacceptable to limit the valuation of the commodity forward contracts to the duration of the active market period.

Energy commodity prices have characteristics not encountered in the financial markets. The volatility of the price of oil, natural gas and especially electricity is a lot larger than that of currencies, interest rates and equities, especially in our present turbulent financial times. Energy prices often exhibit mean reversion, seasonality, sharp and asymmetric spikes that require the development of advanced price models.

Basically, there are different stochastic processes available in order to describe potential future prices of commodities with the two most common used for energy price modeling being the geometric Brownian motion (GBM) and the mean-reverting process although there is no consensus in literature which approach is appropriate. Despite their relative simplicity they are frequently used to model fossil fuel prices. Both processes are based on the fact that the future price depends only on the current price, while older prices are irrelevant for future prices.

In order to capture uncertainties associated with prices a stochastic process is discussed for electricity prices, fossil fuel prices and carbon allowance prices.

6.2 Modeling the price of fuel

Early works in the field of fuel price modeling are often based on GBM.. When fuel prices are used as an input parameter for fundamental electricity market models, the approaches that are most commonly used to simulate fuel prices are GBMs (e.g., Botterud, 2003[60]) or mean-reverting processes.

Even though a wide variety of fuel price forecasting models exist, the quality of forecasts derived from these models is often disputable. Manera at al.,2007[61] presented a review of different models used to forecast oil prices where he found that there is no consensus. Findings vary across models, time periods and data frequencies. The authors conclude that the best performing econometric model for oil forecasts is yet to be presented in literature. While the above paper surveyed oil price models, the results are most probably also applicable to gas price models as found in many countries e.g. Germany.

Summarizing the results of the literature on fuel price forecasting, two things should be kept in mind. First, a perfect forecast model does not exist and second, even if the appropriate stochastic process for a fuel price model could be identified, the forecasts might still differ depending on the historical data used to estimate the parameters of the process. Furthermore, a growing number of experts claim that the price of crude oil nowadays is impossible to forecast as it is not set exclusively according to the traditional relation of supply to demand, but is instead to a big extent controlled by an elaborate financial market system as well as by major oil companies. Perhaps as much as 60% of today’s crude oil price is pure speculation driven by large trader banks and hedge funds (F. William Engdahl, 2008 [62]). These findings emphasize the importance to consider a wide variety of different fuel price scenarios in a power plant investment model.

6.3 Modeling Carbon Prices

6.3.1 Introduction

The uncertainty concerning the development of the emissions allowances price can influence the profitability of power plants which act under the EU ETS and thus is an important factor for investment decisions in carbon-abatement technologies. Consequently the determination of the carbon price risk is a necessary prerequisite to make concrete decisions regarding investment alternatives. Furthermore, electricity is generated by a mixture of different technologies, which differ considerably with respect to their technical characteristics and which are influenced in their generation profitability by carbon prices.

Recent empirical papers help explain the evolution of past prices on the European carbon market (see section 4.3), but the little carbon price history makes it difficult to simply rely on this literature for prospective investment decision-making. The choice of the relevant approach for modeling the carbon as an underlying asset must help in the long-term irreversible decision making.

6.3.2 Literature Review

Knowledge of the statistical distribution of emission trading allowances becomes crucial in setting strategies in the carbon market. Only a few models for CO_2 price simulation exist because of the recent history of the emission trading system. Most of the existing models take into account spot prices.

Paolella and Taschini, 2006 [63] analyzed the CO_2 emission allowance spot prices while discussing forecast methods based on the analysis of a variety of factors, including analysis of supply and demand fundamentals and also based on the spot-future parity.

They showed that these two approaches lead to implausible conclusions due, respectively, to the complexity of the market and to the particular behavior of the emission allowance commodity. To be more specific, concerning the first approach, Paolella and Taschini examine whether fuel prices can be used as a proxy for CO_2 prices with the authors report that the fuel price level does not fully explain the CO_2 price level in 2005. According to the second approach Paolella and Taschini claim that the spot-forward parity approach is, inadequate due to the inconsistent behavior of the CO_2 emission allowance convenience yield (which depends on the political uncertainties that largely affect long futures maturities). As an alternative, Paolella and Taschini propose different GARCH models.

Benz and Trueck, 2009[64] analyzed the short-term spot price dynamics of CO_2 emission allowances by investigating several approaches for modeling the returns of emission allowances while They identified stylized facts of European carbon prices like mean-reversion, jumps and spikes, and heteroskedastic volatility and upon this they investigated the adequacy of different stochastic models for CO_2 allowance logreturns. They first showed that current approaches for CO_2 price scenario delineation are not sufficient because the fundamentals analysis based on few market components overlooks the complexity of the variables that come into play. Due to different phases of price and volatility behavior in the returns, they suggested the use of AR-GARCH models for stochastic modeling.

Dannenberg and Ehrenfeld, 2008[65] assume that carbon prices fluctuate around the expected marginal abatement costs and propose to model carbon spot prices with a mean-reverting process. By introducing the price jumps Dannenberg and Ehrenfeld took into consideration the effects of new information that can significantly change the expectations of marginal abatement costs.

Daskalakis et al., 2009[66] analyze spot and future prices of different markets within the EU ETS which are NordPool, PowerNext and the European Climate Exchange (ECX). Their empirical analysis indicated that emission allowance spot prices are likely to be characterized by jumps and non-stationary behavior. The writers tested six different stochastic processes which have shown best results for a GBM with jumps. In addition to spot prices, Daskalakis et al. examined two different types of futures: intra-period futures and inter-period futures. The maturity of intra-period futures is within the same emission allowances trading phase in which they are first traded. The maturity of inter-period futures is not in the same phase in which they are first traded While intra-period futures evolved closely with spot prices, there were significant deviations for inter-period futures. Inter-period future prices are reported to be higher and less volatile than those of intra-period futures. A possible explanation for that observation is the prohibition of banking of emission allowances between phase I and phase II of the EU ETS.

In a policy-oriented study of investments under climate policy uncertainty, Blyth et al.(2007) [67] and Yang et al. (2008) [68] model the price of carbon as a Geometric Brownian Motion (GBM). Yang and Blyth (2007) [69] further improve their modeling of carbon price by simulating possible carbon price shocks that would represent policy-related events by adding a jump feature to the stochastic modeling (only once in ten years from when the initial investment decision can be first taken). The GBM is fitted using a mix of IEA projections and judgmental input. This study will be further discussed in chapter 8.

The brief literature review shows that a consequence of the relatively short existence of the EU ETS is the absence of established price forecasting models especially for long-term price forecasts which are required for power generation expansion models. Therefore, most power generation expansion models use either deterministic carbon prices (which means that the investor does know what the future prices will be) (e.g., Sun et al.,2008 [70]) or consider different predefined scenarios within the optimization.

6.4 Modeling electricity prices

6.4.1 Modeling electricity prices as stochastic processes

6.4.1.1 Introduction

For any type of power plant valuation an indispensable input are electricity prices in order to valuate investments and profitability, as the revenues generated by power plants strongly depend on them, thus the determination of the electricity price is of great importance.

There are two different approaches to model electricity prices. They can either be modeled as a stochastic process, similar to the way fuel prices are commonly modeled. Alternatively, a fundamental electricity market model can be used to determine electricity prices depending on the current fuel prices, electricity demand and electricity supply. The most commonly used investment models in literature are based on fundamental electricity market models as these are better suited to consider the relationship between fuel prices, carbon prices and the existing power generation portfolio on the one side and electricity prices and electricity production on the other side.

6.4.1.2 Literature Review on stochastic process models

No consensus about the best applicable method derived from the review. Deng, 2005[71] proposes three different mean-reverting jump-diffusion processes for modeling electricity spot price. Deng includes in these models an additional process, which may be correlated with the electricity prices. This other process can be the spot fuel prices or the electricity demand. To account for short periods of high electricity prices, which may be caused by forced plant outages, Deng extends the basic model to a regime-switching model. This extended model allows to switch between normal states and high price states.

Burger et al.,2004 [72] develop a model considering seasonality, mean-reversion, price spikes and price-dependent volatilities. Their model is a three-factor model consisting of a stochastic load process, a short-term process and a long-term process. While the stochastic load process combined with the deterministic supply function represents the part of the price explained by fundamental data, the short-term and long-term process are used to account for price determinants like psychological facts or the behavior of speculators.

Geman and Roncoroni, 2006 [73] introduce a “jump-reversion” component in their spot price model to account for price jumps. They define two different states based on a threshold value. If the current price is below the threshold, only positive jumps can occur.

While if the price is above, only negative jumps are possible. The intensity of the jumps may be time-dependent. As this short literature review indicates, there are many different stochastic processes used to model electricity prices most of which have in common the inclusion of fundamentals to improve price forecasts.

6.4.2 Modeling Electricity Prices with Fundamental Models

Fundamental electricity market models calculate the cost-minimal electricity production for the considered market which can be used to determine the electricity production of each unit as well as electricity prices. The main advantage of fundamental electricity market models compared to simulation models is the more appropriate consideration of the relationship between fuel prices, electricity demand and electricity supply on the one side and electricity production and electricity prices on the other side.

Depending on the type of fundamental market model, they can also consider short-term uncertainties, e.g., the feed-in from wind power, as well as technical restrictions of power plants like reduced load efficiency. For these reasons, we argue that fundamental electricity market models are best suited to model electricity prices for the valuation of power plant investments although they face several difficulties, which are be mentioned in the following:

- Most fundamental electricity market models rely on the assumption of a competitive market which is still not the case nowadays for most European countries, not only regarding markets like the greek energy market which needs a long way to go to accomplish deregulation but for most evolved markets like the german energy market as well.
- In order to be able to make long-term price forecasts, assumptions about future market conditions like fuel prices or the existing power plant mix must be made which is a difficult task.
- Fundamental electricity market models cause a high computational burden.
- There is no data availability. While the data required for stochastic process models (financial and econometric) is in general available in public (e.g., historical electricity prices), the exact technical parameters of power plants are often not publicly known.

In the following, we briefly describe three different kinds of fundamental electricity market models, which can be used to determine the contribution margins of new units for an investment model.

- **Load–duration curve (LDC):**
  Fundamental models based on the LDC are the simplest type of fundamental models. The LDC for a whole year is used to determine the corresponding electricity production and prices. LDC models do not consider any technical constraints.

- **Supply–demand curves (SDC):**
  These models use several different SDCs to determine electricity prices. As the models based on the LDC, these models do not consider technical constraints. However, models based on the SDC can consider a price elastic demand.

- **Linear programming (LP) models:**
  These models describe the power generation as an LP problem while having the possibility to model technical constraints like minimum operation or minimum shut-down restrictions. Furthermore, short-term uncertainties like the demand or the feed-in from wind power can be considered. The disadvantage of such models is the enormous computational burden.

6.5 Conclusions

Taking into consideration the risks to which power plant investments are exposed which are fuel, carbon, and electricity price uncertainty as well as uncertainty about the legal framework, in this section we described different approaches to simulate fuel, carbon and electricity prices. There are a wide variety of different stochastic processes used for the simulation of these prices, and there is no consensus in literature which approach is appropriate. In our opinion, the difficulties related to fuel and carbon price modeling lead to consideration of a wide variety of different scenarios.

As the different risks are highly interrelated, it is important that this relationship is captured by the method used to determine future contribution margins for new units, with the fundamental electricity market model proving best suited for this purpose.

Furthermore we presented briefly three different kinds of fundamental electricity market models, which can be used to determine the contribution margins of new units for an investment model. In general, the LDC model tends to underestimate prices in times of high load periods, while it overestimates prices during low load periods. On the other side, the advantage of electricity market models based on an LP formulation is their ability to consider technical restrictions of plants as well as uncertainty.

CHAPTER 7

VALUATION OF POWER PLANT INVESTMENTS UNDER UNCERTAINTY

7.1 Introduction

In the previous sections we have described the risks to which power plant investments are exposed and how these affect operational decisions. We have concluded that the uncertainties discussed have a strong influence on the profitability of power plants investments which have to be considered by power plant valuation methods. In this section we will introduce a few of the valuation methods that investment companies typically use to make their investment decisions.

According to Yang and Blyth, 2007 [69] investments in the power utility industry show three important characteristics: Firstly, they are more or less irreversible. Secondly, the future prices of inputs (e.g. fuel, emissions) and outputs (electricity) are influenced by uncertainty, which could have a major impact on a company’s financial performance. Thirdly, investment decisions can be made under flexible timing conditions. Thus, a good project evaluation and investment methodology should quantitatively satisfy all the three above mentioned characteristics : irreversibility, uncertainty and flexibility.

As mentioned above, in regulated energy markets, the costs of power supply are practically transferred to end consumers, guaranteeing that all costs could be principally recovered . In liberalized markets, on the contrary, it is necessary to optimize profitability (i.e., revenues minus costs) and risks, rather than only to minimize cost.

Therefore short-term and long-term investment strategies are needed which can be selected by adopting different decision rules.The concept tool box of the decision-maker includes different methods which can be applied for this task, on one side there are simple methods like the DCF, the levelized cost and the screening curve analysis, on the other side more sophisticated methods like the real options method which require a strong mathematical background.

The real options approach, which is a method developed for investments under uncertainty, became popular to evaluate power plant investments in a deregulated market, which contrary to the LCOE approach, it takes the timing of investments into consideration.

In the following, we first give a brief overview of the power plant decision factors for an investment strategy, then we will describe the DCF analysis, the LCOE method and the screening curve method. Furthermore, we refer to more sophisticated approaches introducing the real options approach and provide a review of power generation expansion planning modeling techniques .Finally we introduce a literature review on the impact of EU ETS on investment decisions.

7.2 Power plant decision factors for an investment strategy

The EU ETS provides a driver for investment in lower carbon intensity generation. To this extent it should encourage investment in existing plant to reduce carbon intensity. According to IPA Energy, 2003 [95], a brief overview of a number of ways of reducing carbon intensity from a technical point of view follows :

- **Fuel Switching within plant**

  Some plants have dual fuel capability, and so can reduce carbon intensity by switching fuel. Although it would be possible to retrofit dual firing with gas at coal stations, there is a relatively large cost associated with such adaptations and connection to the gas transmission grid. In addition, the reductions in carbon intensity are much lower than those that would arise from the construction of a new CCGT.

- **Fuel Switching within a Generation Portfolio**

  Most of the portfolio generators have a mix of generation technologies within their generation fleet. Portfolio generators will constantly optimize the running time within their portfolio in response to changing demand, outages and commodity prices. Thus, the EU ETS simply provides an additional parameter that should be taken into account within this optimization procedure, and should not lead to increased administrative costs.

- **Investment in New Generation Capacity**

  A key response to the EU ETS will be through investment in new generation capacity with lower carbon intensity. New CCGT plants are expected to replace a huge capacity of coal plants projected to become uneconomic over Phase II through a combination of changing commodity prices and the EU ETS. Further new generation capacity is expected to be required to replace nuclear plant capacity expected to close over Phase II, as well as to meet underlying demand growth. While the EU ETS will not provide the primary driver for these latter investments, the existence of a price for carbon emissions will provide an incentive to minimize the carbon intensity of any new generation.

- **Improvements in Generation Efficiency**

Although in theory it may be possible to improve generation efficiency at some stations, the high fuel component in the marginal cost of generation has meant that the power sector has always been extremely focused on maximizing the efficiency of plant, although it has to be accepted that there is often a trade-off between optimizing efficiency and maintaining plant flexibility (for peaking plant, the ability to respond quickly and having low fixed costs to spread over short periods of generation may be more important than efficiency of generation). Thus, it is unlikely that significant improvements in generation efficiency of existing plant will be made as a direct response to the EU ETS.

- **Investment in JI/CDM Projects**

Investment in JI/CDM projects could give players access to cheaper emissions credits from abroad (CERs and ERUs). It is likely that this route may be pursued by some of the large pan-European utilities, but this has not been investigated in detail in this report.

7.3 The discounted cash flow (DCF) analysis and the "NPV-rule"

The classical and simplest way to assess an investment is based on the assumption that power players will decide the optimal strategy on the basis of a the discounted cash flow (DCF) method: The DCF valuation method consists in discounting to present value all the future cash flows minus the initial investment outlay, and in accumulating them to find the net present value (NPV) of the investment. Corporate finance textbooks present the "NPV rule" as the key to making investment decisions: any investment with a positive NPV is a good investment and should be pursued. (A.Damodaran, 2011, [74]).

In the presence of uncertainty, a risk premium may be imposed on the NPV calculation by employing a risk-adjusted discount rate, and appropriate sensitivity and scenario analyses may be performed.

As discount factor, the firm's weighted average cost of capital may be used. The general formulation of the NPV is as follows:

$$NPV = \sum_{t=0}^{T} \frac{R_t}{(1+r)^{t'}} + \frac{L}{(1+r)^T} - I_o$$

Equation 7.1: Net Present Value

with *Rt* equal to the returns in year *t*, Io the initial investment, *L* a possible salvage value, *r* the discount rate and *T* the life of the project. The NPV decision rule for an independent investment is accepted if the NPV is positive. If one among of several mutually exclusive investments has to be chosen, the one with the highest NPV has to be collected. The NPV can be seen as the value of an investment giving information about the minimum return without considering uncertainty.

In addition, the expected internal rate of return (IRR) is often also calculated, indicating the (implicit) discount rate that yields an NPV of zero. This is then compared with some hurdle rate imposed by the investor for a particular type of project that makes sure that the risk taken does not lead to a reduction in the investor's credit rating, as this would raise the cost of debt financing (Gross et al., 2007[16]).

As far as power plant investments are concerned, according to this methodology, the decision to switch from a given power generation technology to another should be undertaken whenever the present value of the profits generated by less polluting technology exceed the present value of the profits of the more carbon intensive one .

Many power companies run detailed models of the electricity system they are considering making an investment, with major generation plant represented. Such models may be used to assess possible financial outcomes, hence risks, by either generating a set of NPVs from a set of discrete scenarios and/or a by generating a spread of NPVs using a stochastic approach. As analyzed in chapter the major variables that affect the financial performance of the power plant include utilization, fuel prices,CO_2 prices, electricity prices and the value of support mechanisms such as the RO. The impact of investment behavior of other players in the market may also be incorporated.

7.4 The Levelized cost valuation method of electricity generation

This is a widely used approach for comparing electricity generation costs. Many studies have been published in recent years that have relied on this method,(see Royal Academy of Engineering, 2004[75]).

The majority of day-to-day investment decisions in the power sector involve choosing the least-cost solution that takes into consideration all realistic alternatives able to satisfy the project objectives (Khatib, 2003[76]). To calculate abatement costs a method of comparing technologies on an adjusted basis has to be implemented. Technologies have different usage profiles and lifetimes which makes direct comparison difficult.. The method by which this is done is known as LCOE or Levelized Cost of Electricity. LCOE is widely accepted and adopted by the IEA, US Department of Energy and the UK government (Gross et al., 2007[16]).

The levelized cost approach is a specific case of DCF analysis, which reverses the procedure: given the objective of zero economic profit, the required annual revenues are calculated so that the present value of all revenues exactly balances the present value of project costs. The levelized cost methodology inherited from the pre-liberalization times has been a useful tool for investors and for overall economic analysis because it evaluated costs and energy production and discounted them to take account of the time value of money.

In this method the cost per kWh of electricity or the annual cost of owning and operating a generating plant is calculated to compare different technologies. The LCOE is based on the discounted cash flow (DCF) analysis.. In this method the required annual average costs of an electricity generating system in € /MWh are calculated including all the discounted costs that occur over its lifetime: initial investment, operations and maintenance, cost of fuel, discount rate and is very useful in calculating the costs of generation from different sources. They are calculated in such a way that the NPV of a possible power plant investment is zero. The LCOE are defined as (see, e.g., IEA 2010[77]).

$$LCOE = \frac{\sum_{t=1}^{n} \frac{(I_t + M_t + F_t + C_t)}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

Equation 7.2: LCOE

with *It* = Investment expenditures in year t [e],

Mt = Operation and maintenance expenditures in year t [e],

Ft = Fuel expenditures in year t [e],

Ct = Emission allowance expenditures in year t [e],

Et = Electricity production in year t [MWh],

r = Discount rate,

n = System lifetime.

The evaluation of different investment alternatives demands the calculation of the LCOE for each investment alternative while the project with the lowest LCOE is the finally chosen one.

An example of an LCOE calculation is shown in figure (IEA, Projected Costs of Generating Electricity 2010 Edition, executive summary [77]) : where the results are plotted after a study which was carried out by IEA focused on the expected plant-level costs of baseload electricity generation by power plants that could be commissioned by 2015. The study concerns 111 plants (34 coal-fired power plants without carbon capture, 14 coal-fired power plants with carbon capture, 27 gas-fired plants, 20 nuclear plants, 18 onshore wind power plants, 8 offshore wind plants, 14 hydropower plants, 17 solar photovoltaic plants, 20 combined heat and power (CHP) plants using various fuels and 18 plants based on other fuels or technologies) from 16 OECD member countries. With the most important assumptions being a low real discount rate 5% and a carbon price of USD 30 /t CO_2.

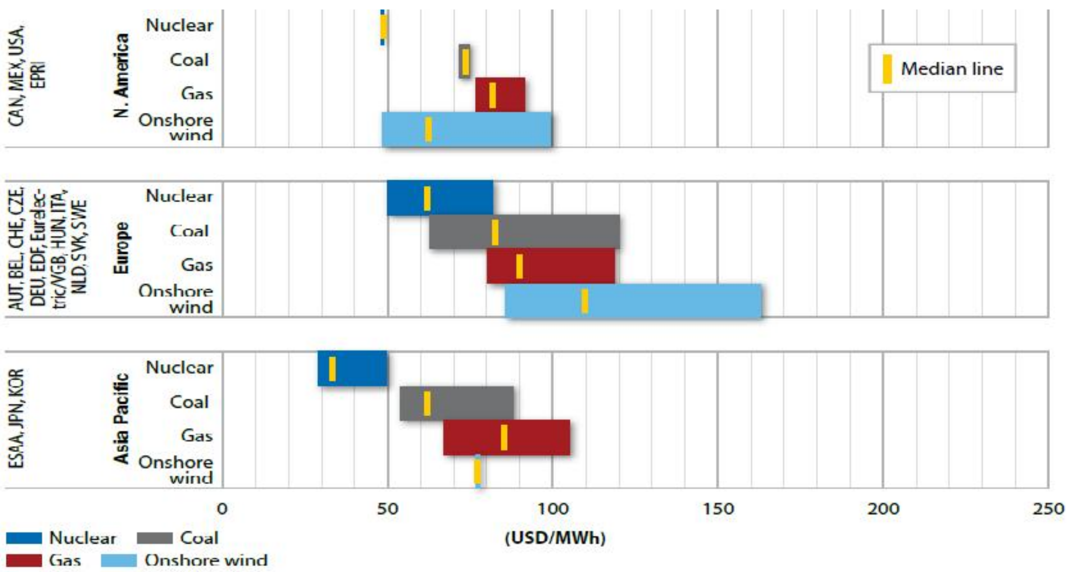

Figure 7.1: Regional ranges of LCOE for nuclear, coal, gas and onshore wind power plants at 5% discount rate (source: IEA, 2010 [77]).

From Figures 7.1 and 7.2 the following derives that competition in electricity markets for baseload generation is today split between nuclear energy and natural gas-fired combined cycle power generation, with coal-fired power generation not being competitive once carbon pricing is introduced.

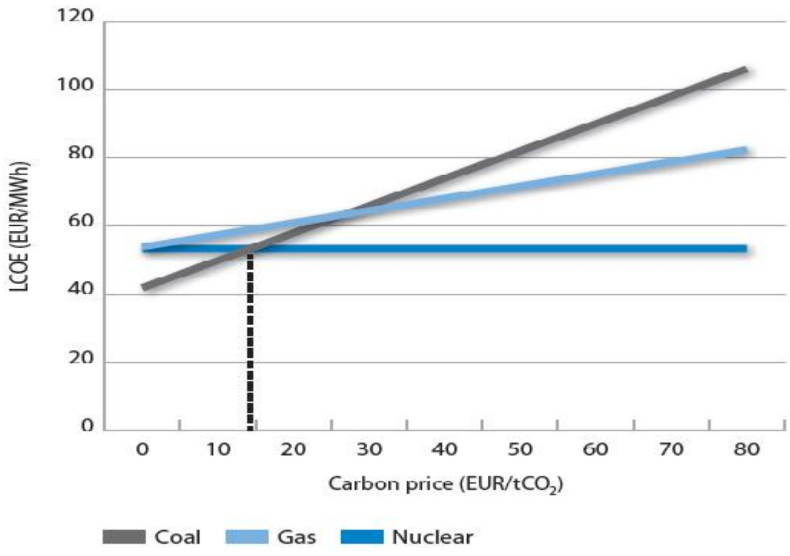

Figure 7.2: Carbon Pricing and the competitiveness of nuclear energy in OECD Europe : LCOE of different generation technologies at 7% discount rate, source OECD 2011,[12].

Similar to our remarks about the application restrictions of the NPV method, the LCOE concept too was a popular method for project valuation in regulated markets being sufficient to minimize costs but not able to optimize returns and risks which is necessary in liberalized markets. In the presence of uncertainty, appropriate sensitivity and scenario analyses must be performed in order for the decision-makers to understand the tendencies which lead to the best possible investment decisions. Figure 6.3 shows the sensitivities of two reference technologies; nuclear which has low fuel costs and high capital costs and a Combined Cycle Gas Turbine (CCGT) which has high fuel cost and low capital cost. As the parameters are changed, significant differences in the generating costs comes to light. Figure 3.10 illustrates that at relatively high capital cost, low fuel cost technology is sensitive to variation in discount rate and insensitive to fuel price variation. The opposite is true for a low capital cost, high fuel cost technology. The key message however, is that even if there is some agreement over the construction and operating costs of particular technologies, wide variations in levelized cost estimates can result from the other factors – and that these factors will affect cost estimates in different ways depending on the characteristics of the technologies.

A discount rate raise from 5 to 10% makes the electricity generation costs in the nuclear plant to rise higher than in the CCGT. On the contrary, if fuel price is raised by 20

% the electricity generation in the CCGT becomes not feasible compared with the nuclear unit in which the generation costs remain hardly affected.

What is not shown in Figure 7.3 is the interactions that occur between all these factors and changes in the merit order. E.g., if the price of natural gas drops to where it becomes cheaper than nuclear, the CCGT plant can change merit-order and become base-load, lowering the load factor for a nuclear and further affecting its profitability.

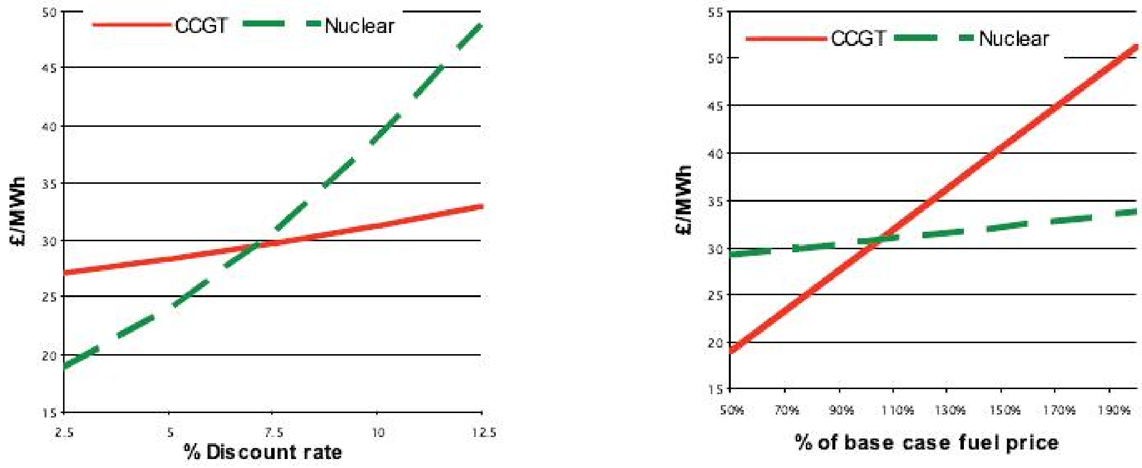

Figure 7.3: Sensitivities of Electricity Generation Costs (Gross et al., 2007[16]).

In the presence of uncertainty and the irreversible nature of power generation investment, LCOE calculations are inadequate and therefore need to be complemented or replaced by improved methods. Some of the disadvantages concerning the suitability of LCOE calculation are described next:

1. Omission of uncertainty

In the LCOE calculation only expected values are taken into consideration. Instead the significant parameter of uncertainty is ignored. With the performance of sensitivity analysis in which the LCOE values are calculated as a function of a chosen input parameter but with all the other parameters remaining fixed, only restricted results can be achieved. Especially concerning fuel and carbon prices which are suffering a high volatility in reality they should be taken into account adequately by a power plant valuation method.

2. Omission of evaluation of the investment profitability

The LCOE is only capable in determining the cheapest technology based on the assumption that an investment is needed. In deregulated markets unlike regulated markets, generation companies will chose to invest only if an investment is profitable. But the LCOE method, which compares current electricity prices with the calculated LCOE values do not take into account the uncertainty related to future electricity and carbon prices.

3. No consideration of time

One very important issue concerning power plant investments is the timing of the investment. The NPV method (besides the LCOE method) is based on the assumption that the investment is reversible, meaning that it may be withdrawn sometime in the future and furthermore the costs can be recovered In reality, investments are more or less irreversible, since the plant generally cannot be resold without losing considerable value. The option for a power company in situations of uncertainty (e.g. a new allocation period in an emissions trading scheme),is the possibility to delay an investment for some other future time. In these situations, a greater project payoff may be obtained by waiting until the uncertainty has been resolved than by investing immediately.

7.5 Screening Curve Method

The screening curve method is a graphical plot of the annual levelized costs for different capacity factors with the levelised costs being plotted on the vertical axis and the capacity factor along the horizontal axis (Figure 7.4).

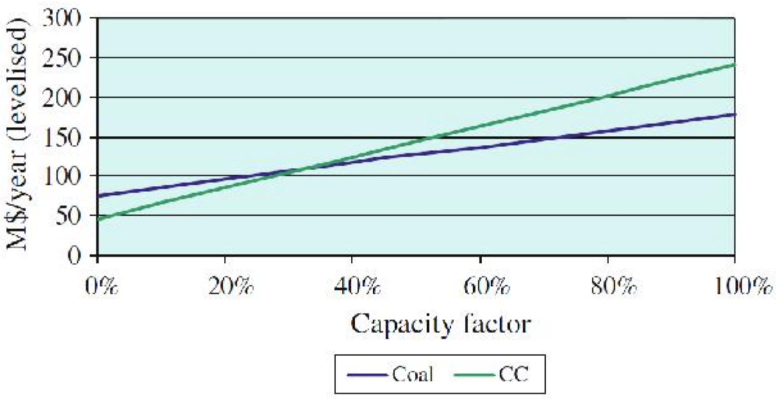

Figure 7.4: Screening curve (Bhattacharyya, 2011[78]).

The combination of the screening curve analysis with the load-duration curve enables the determination of the requested generation mix of a power system. (Figure 7.5 Bhattacharyya, 2011[78]).

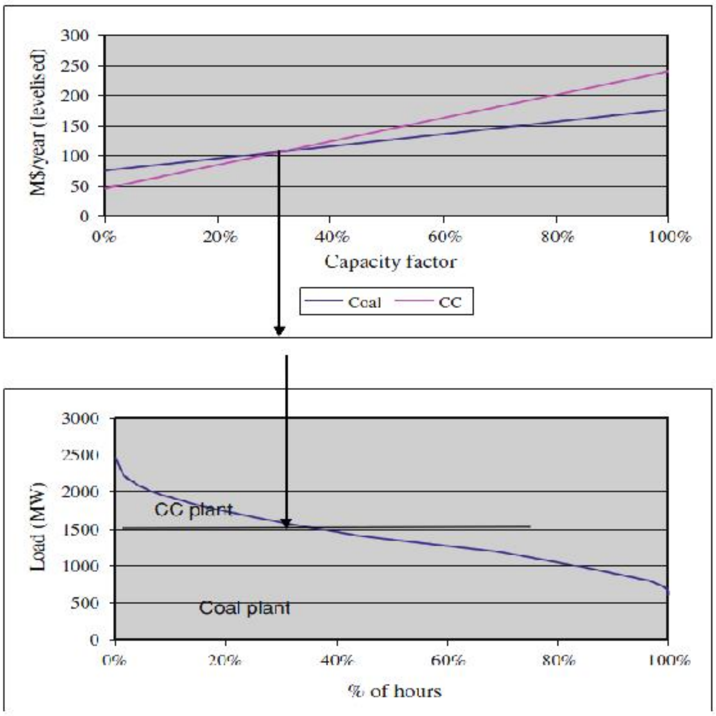

Figure 7.5: Screening curve and Load Duration (Bhattacharyya, 2011[78]).

The screening curve is a useful tool in order to understand the role of different technologies in the power utility sector because it focuses on the strategies concerning system optimization. Despite the fact that it requires restricted amount of information, it is capable in capturing the interdependence of capital and operating costs and the utilization levels of the different generation technologies. However according to Bhattacharyya, 2011 [78]) ‘*’it is not adequate for detailed production cost analysis or system expansion analysis because it fails to capture the issues related to system reliability, resource constraints, differences in characteristics of new technologies and the old technologies, etc*.’’

7.6 Power utilities strategic behavior and the real options approach

7.6.1 Introduction

While in the short run power generators can only adjust their production mix, in the medium and long run there is additionally the possibility to undertake new investments towards less carbon intensive technologies. Such a long-term investment strategy can be chosen based on different decision rules. We have discussed in chapter 7.3 the classical approach which is based on the assumption that power decision makers will pick the optimal strategy according to the Net Present Value (NPV) approach deciding to switch from a given generation technology to another whenever the present value of the profits generated by a less polluting technology exceeds the present value of the profits of the more carbon intensive ones.

The disadvantages of this approach is that it does not take into account the crucial factors of uncertainty, irreversibility and managerial flexibility, leading to inaccurate judgements concerning the investment opportunity value of potential ,low carbon projects. With investments in the power sector being irreversible and with long-term decisions which need to be taken under all kinds of uncertainties (concerning for e.g. fuel costs, electricity prices and emissions trading costs, etc.), new tools are required, which will be able to tackle the problem better than the conventional DCF approach.

An example of such an approach is the real option-based approach (ROA) which will be first introduced in the following section and then incorporated in the power utilities investment decisions scheme.

7.6.2 The Real Options approach

Real option valuation is an adaptation of the theory of financial options, often employed in the valuation of investment projects. It recognizes that the business environment is dynamic and uncertain and that value can be created by corporate leadership which identifies and exercises managerial flexibility over the entire life of the project. Furthermore, a real option is a permit with different value at different time periods to undertake some business decision, typically an option to make a capital investment. By purchasing a permit e.g., a firm may have the real option of expanding, downsizing, or abandoning other projects in the future. By investing in R&D, the firm may have real options for further business development, mergers, acquisitions etc. Practically with such options, the firm will be able to flexibly manage its irreversible investment capitals, and at the same time, taking into account the uncertainties and risks of future cash flow.

In the context of costly emissions, profit-seeking firms can invest in a new technology (e.g. a “clean” power plant) early if they think the return on investment is high enough to compensate them for the risks involved, or they can postpone the investment to acquire more information on some of those risks.

Furthermore, it has to be mentioned that the ROA valuation is not considered as an alternative valuation method to the DCF, but rather as an expanded DCF. In the expanded DCF, the value of any investment consists of two components: the traditional (static) NPV of the direct cash flows, and the option value of the managerial flexibility. The difference between the traditional DCF value and the real options value is shown in Figure 7.6.

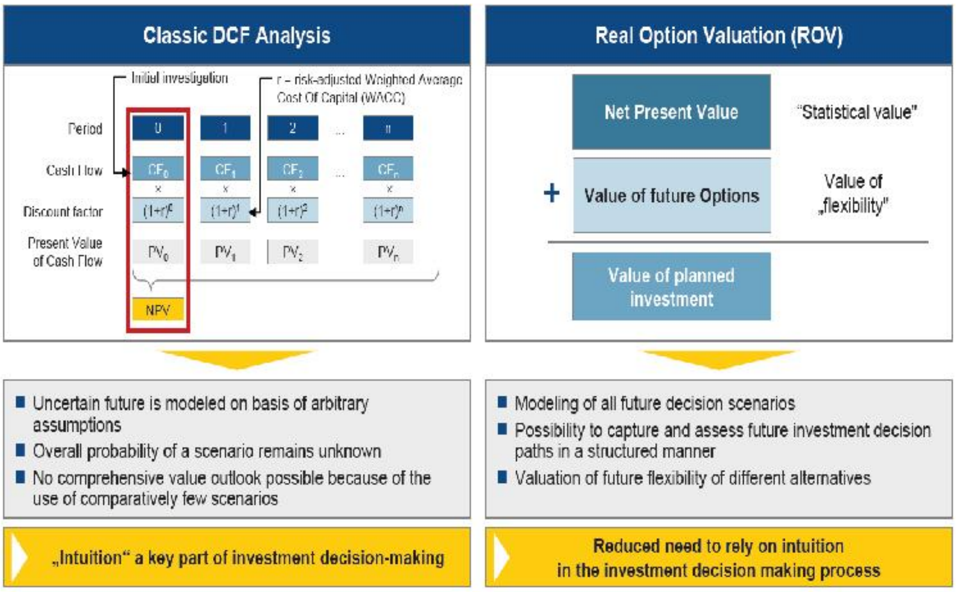

Figure 7.6: Real Option Valuation methodology – Comparison of ROV and classic discounted cash flow methods source, Arthur D.Little, 2008[79].

The very characteristics of power plant investment decisions makes it particularly relevant to use the ROA which has been actually applied to peak-load power plant valuation, hydro power plant valuation (taking into account the flexibility in managing the water level in its reservoir) and fuel switching in IGCC plants .

Despite the above described advantages of ROA , surveys indicate that real options techniques are not widely used in a commercial setting within the electricity industry.(Gross at al., 2007[16]).

7.6.3 Real options incorporated in power utilities investment decisions

Sapienza and Stefanoni, 2007[80] analyzed the impact of the ETS scheme on the power sector and presented a roadmap describing how investment decision making is accomplished by power utilities.

First of all they distinguished between two different situations: one describing the problem of incumbents and a second for all new entrants. Incumbents are the holders of a switch option who have the right, but not the obligation, to undertake an investment in order to switch from the currently used technology to a less polluting technology. Switching options are complex portfolios of call and put options and incumbents will eventually switch among different production modes more than once during the actual operational life of the power plant. Nevertheless, it has been recorded that in the power sector switching from one technology to another involves such high investment costs that chances of an operator switching more than once are most unlikely to occur. For this reason, the authors of this paper consider just a single switch. This assumption allows the consideration of the switch option as a simple call option giving its owner the possibility to exchange the currently used technology, with another, the new introduced technology.

The new entrant is the owner of an option to wait, giving him the right, but not the obligation, to invest in the market with one of the currently available technologies.

A typical approach to ROA power plant valuation involves directly modeling the spark spread (Figure 7.7):

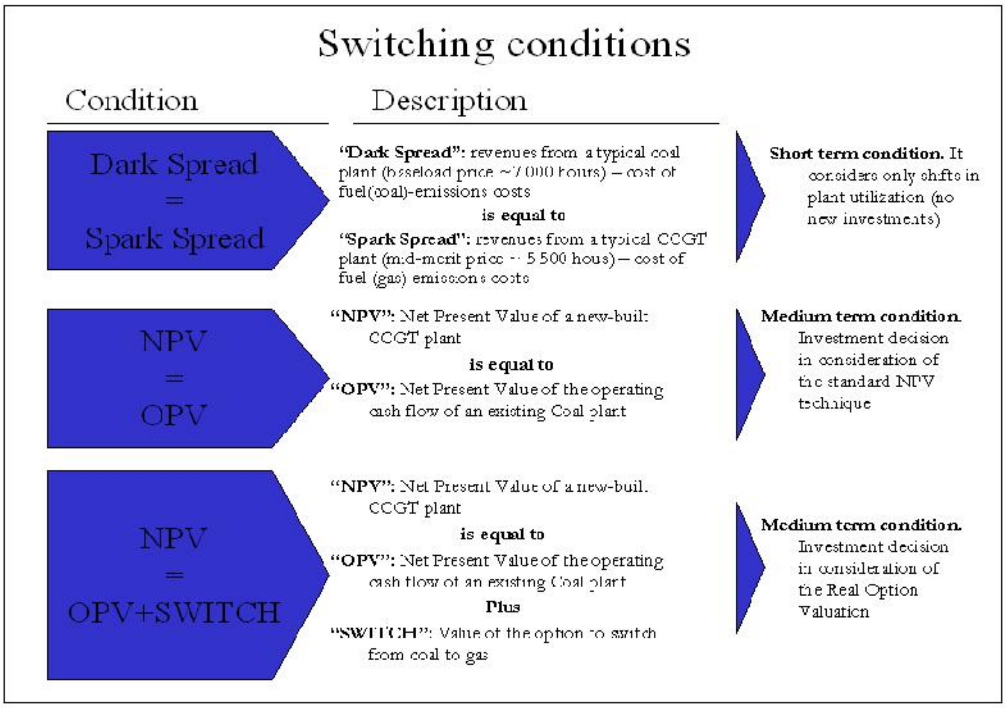

Figure 7.7: Switching conditions for the incumbent (source: Sapienza and Stefanoni, 2007[80])

Regarding the short run switching conditions , the condition which makes the operator indifferent concerning the 2 technologies is the EUA price which equates dark and spark spread. In such a case changes in plant utilization are considered while no additional investments are undertaken.

Regarding the medium run switching conditions, the EUA's threshold level have to be calculated for two specific conditions.

The second condition (NPV=OPV) holds if there is no uncertainty regarding the investment outcome ,which is the case if both fuel and EUA prices will remain constant over the operational life of the two power plants. In this case the price of EUA which causes the incumbent's indifference concerning the choice between the two technologies is the one that equates the operating NPV of the existing coal plant to the NPV of the new constructed CCGT.

Finally, regarding the third switching condition, (NPV=OPV+SWITCH), the uncertainty concerning the investment is taken into consideration by applying the Real Option Approach. According to the ROA theory, in order to optimise the switch, the NPV of the new built CCGT with a given EUA price, would have to be high enough to offset the opportunity cost of abandoning the option.

7.7 Power Generation Expansion Planning Models

7.7.1 Introduction

Prior to energy markets liberalization, large state-owned utilities developed capacity expansion planning models which were able to determine the least-cost investment route, given the plants in existence and different environmental and policy constraints .

The development towards electricity market competition and the constant growth of different renewable power sources has pushed the research community to efforts to develop decision and analysis support models adapted to the new energy market context.

Different classifications of decision support models concerning long-term electricity planning exist. Ventosa et al.,2002 [81] present a review of the most recent publications regarding electricity market modeling where they identify three major categories: optimization models, equilibrium models and simulation models. These models differ mainly in their mathematical background and market representation.

Optimization models focus on the profit maximization problem for one of the firms competing in the market, while equilibrium models representing the overall market behavior taking into consideration competition among all participants Finally Simulation models are an alternative to equilibrium models when the problem under consideration is too complex to be addressed within a formal equilibrium framework.

From a structural point of view, the different approaches that have been proposed in the technical literature can be classified according to the scheme shown in Figure 7.8.

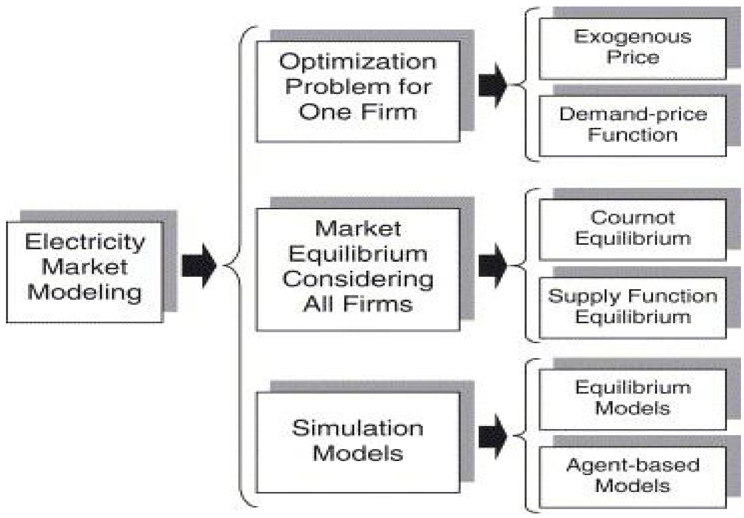

Figure 7.8: Schematic representation of the electricity market modeling trends, Ventosa et al.,2002 [81].

In the following, we give a brief description of simulation models, game-theoretic models and optimization models. For these models, we consider some additional classification criteria proposed by Botterud, 2003 [60]. These additional criteria are the representation of supply, demand and the electricity market and the representation of investment decisions.

Further references about the expansion planning approach include e.g. International Atomic Energy Agency [82], Foley et al., [83] who present among others a number of key proprietary electricity systems software tools and finally a survey comparing different approaches for power generation expansion planning from monopoly to competition given by Kagiannas et al.,2004 [84].

7.7.2 Simulation Models

The main objective of descriptive electricity market models is to gain insights about the way the electricity market works. Using this knowledge about the functionality of the market, these models aim for predicting the future development of the market. Descriptive models do not rely on the assumption of a perfect market, but can consider market imperfections. This is an important feature, as electricity markets show different types of imperfections (e.g., Lemming, 2005 [10]). Descriptive models are based on a simulation. Two different methodologies are applied to study the long-term development of electricity markets: system dynamics and agent based simulation.

7.7.2.1 System Dynamics

System dynamics describes the development of a complex system with stocks and flows. Its principle is based on the fact that interactions between elements of the power system are analyzed through a set of non-linear differential equations while causal loops and feed-back l loops are used to model the interdependencies between the components of the system under study.

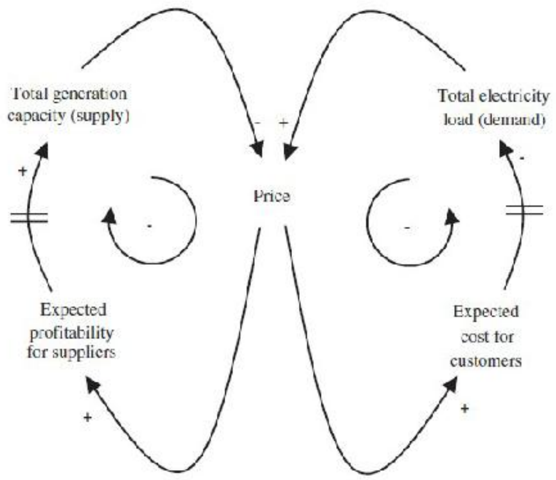

Figure 7.9: 10 Loop diagram for investment in a typical energy market. + positive feed-back;− negative feed-back; = delay. Assili et al, Energy Policy, 2008[85].

There are some applications of system dynamics to long term electricity market modeling. Bunn and Larsen,1992 [86] use a system dynamics model to test how power plant investments are influenced by various regulatory conditions, economic assumptions and the strategic behavior of the separate companies.. Vogstad,2004 [87] uses a system dynamics model to analyze long-term versus short-term implications of various energy policies within the context of the Nordic electricity market. Concerning power generation expansion, he also observes the boom and bust cycle. The same was pointed out by Olsina, 2005[88], who investigates the long-term development of the generation capacity.

7.7.2.2 Agent Based Simulation

While the system dynamics approach assumes a centralized decision maker, the agent based simulation is focused on the study of collective behavior while considering multiple independent agents. Agents are autonomous decision-maker with capabilities which may behave differently concerning observation, communication, computation and action (e.g., based on their risk aversion) or they may face different restrictions. In addition, agents are able to learn. Agent based modeling of electricity markets became popular during the last years. For recent surveys and literature reviews see Sensfuß et al.,2007 [89].

With the desire for a long-term oriented simulation, Czernohous et al.,2003 [90] present a basic agent-based model considering the investment decision within long-term planning of electricity markets. Additionally, regulatory agents are introduced as a third side in the market simulation to represent governmental decisions. This results in the definition of three types of agents representing electricity generating companies, consumers and governmental instances.. The electricity prices are determined by auctions, where the suppliers and customers place their bids. Two different planning layers are used. In the short-term planning layer, the suppliers decide on the plant utilization and the bids for the auction. The long-term planning layer is used to determine the investment decisions. The investment decisions are formulated as an Linear Programming profit maximization problem whereby the profit calculations are based on the electricity prices observed during the last short-term period. The influence of governmental instances is included in the model by regulatory agents affecting taxes on the emission of harmful substances and monitoring prices.

Genoese et al.,2008 [91] study the impact of several emission allocation schemes the power plant investments of the German energy system. The work is based on the PowerACE model, which is an agent based simulation of the German electricity market. An overview of the entire model and the main agents involved is given in Figure 7.10.

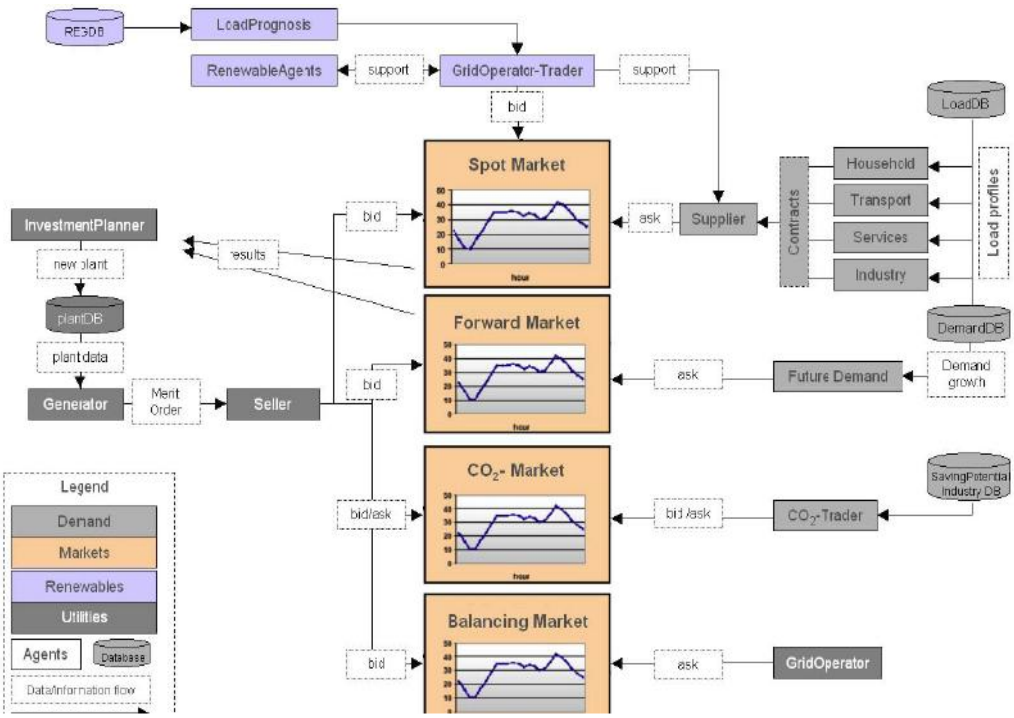

Figure 7.10: PowerACE model overview source, Genoese et al.,2008 [91].

The model includes a short-term spot market and a forward market for electricity, a market for balancing power and a static emission allowances market. The prices obtained at the spot market and the forward market are used to forecast electricity prices, which are required for the investment planner. Based on these predicted prices, the investment planner calculates the net present value for the different investment alternatives. Five different emission allowance allocation schemes are tested with six gas and carbon price combinations. In general an increase of electricity prices can be observed through the introduction of an emissions trading (Figure 7.11).The highest price increase occurs in the case of auctioning where also the highest emission reduction appears (up to 20% with low gas prices). They further observed that the design of the allocation scheme has a significant influence on power plant investments, electricity prices and carbon emissions.

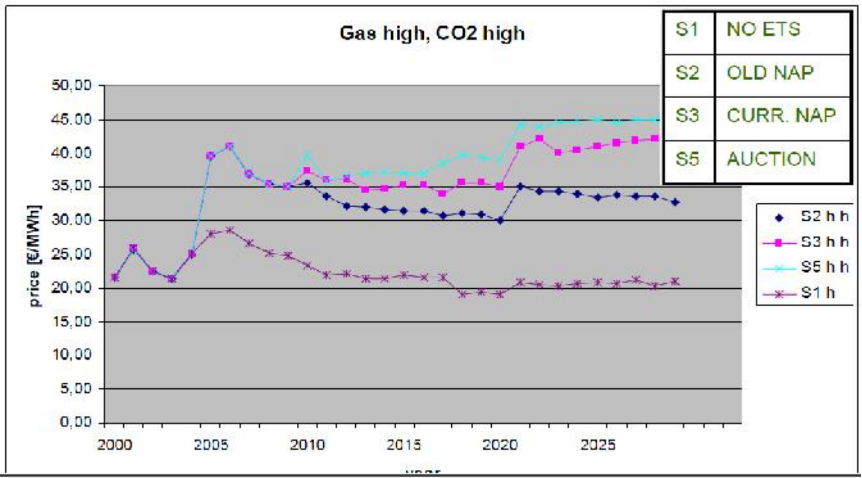

Figure 7.11: Modeled Electricity price in the ‘gas-low’&’CO2-high’ scenario, Genoese et al.,2008 [91].

7.7.3 Game-Theoretic Models

The focus of game-theoretic models lies on the interaction of different market players. Game-theoretic models are especially well suited for markets with not perfect competition like oligopolies, where strategic behavior can be observed. However, they often use a simplified description of the electricity market. Uncertainty, e.g. about future fuel prices is not considered or if, only in a simplistic manner. Game-theoretic models are mainly used to analyze market power and test different market designs. While the majority of the game-theoretic models focuses on short-term questions, there are also some models considering capacity expansions. Literature review in this direction includes Chuang et al.,2001 [92] who study the effect of different levels of competition on capacity expansion, Ventosa et al.,2002 [81] who compared capacity expansion in electricity markets under imperfect market conditions and under different assumptions about the timing of the investments and Murphy and Smeers, 2005[93] who studied capacity expansion in an oligopolistic market comparing the case of selling electricity in long-term contracts with the case when electricity is sold on a spot market.

7.7.4 Optimization Models

Apart from the pre-mentioned fact that optimization models focus on the one –firm profit maximization problem, most of them rely at least partly on the assumption of a perfect competition. The majority of recent optimization models in the field of power generation expansion is based on the real options approach. While these models are not able to represent strategic behavior as it can be done with a game-theoretic approach, they generally model the electricity market and the uncertainties related to power generation expansion in more detail.

Amongst the optimization models, there are important differences in the way the investment decisions and the electricity market are represented. Concerning the representation of investment decisions, Botterud, 2003[60] distinguishes three perspectives: centralized decision making, decentralized decision making considering multiple decision makers and decentralized decision making considering a single decision maker. The representation of the electricity market can either be based on simulation, or on a fundamental electricity market model.

In the following, we first discuss the differences between centralized and decentralized decision making, before we present different power generation valuation approaches based on electricity price simulation. Then, we give a detailed overview of power generation expansion models based on fundamental electricity market models.

7.7.4.1 Representation of Investment Decisions

Centralized decision making can be observed in regulated electricity markets. As these markets are monopolies, there is one single decision maker who controls the whole system. From the modeling approaches presented, the system dynamics approach as well as some optimization models use a centralized decision maker. However, in deregulated electricity markets, there are several competing actors on the market. In such an environment, a decentralized approach considering different market players is more realistic.

Decentralized decision making can be further distinguished. The first possibility is to model several individual decision makers interacting through the power market. The decision makers may have individual objectives or may be restricted by individual constraints. Such an approach is taken by agent based models and also by game-theoretic models. The other possibility is to optimize the investment of a single decision maker, and represent all other decision makers as an aggregated decision maker. The decisions of this aggregated decision maker may be fixed externally or depend on the feedback from the power market. Such an approach is taken by some optimization models. It is often stated that in a competitive market, the social welfare maximization problem leads to the same result as the profit maximization for single generation companies (e.g.,Weber and Swider,2004 [94]). Hence, the decentralized investment problem may be replaced with a centralized approach.

However, as discussed by Botterud, 2003[60], there are several special characteristics of a power market that can distort the social welfare equilibrium. These factors are the limited price elasticity of demand, a price cap introduced by regulators, the potential exercise of market power and the lumpiness of investments. Botterud, 2003[60] compared the outcomes of centralized and decentralized investment models, and concludes that under the centralized model, investments are higher.

From the modeling point of view, it makes a great difference whether a centralized or a decentralized decision maker is chosen. If the contribution margins for new units are determined by a fundamental market model based on an LP formulation, then using a centralized decision maker makes it possible to integrate the investment decisions into the existing model. This is possible because the problem can be formulated as a cost minimization problem subject to demand satisfaction.

Taking the perspective of a single, decentralized decision maker, the demand satisfaction constraint no longer exists in a deregulated market. The objective of the considered decision maker is profit maximization. The profit depends on the amount of produced electricity, the costs for producing the electricity and the electricity prices. While the amount of produced electricity is a variable in the unit commitment problem and the costs can also be expressed as a variable in the unit commitment problem, the electricity prices are indirectly determined as dual variables of the electricity demand constraint. This indirect determination of electricity prices makes it impossible to incorporate the investment decisions into a decentralized unit commitment model.

As a consequence, unit commitment decisions and investment decisions must be taken by two separate models. The investment problem can be formulated as an SDP problem as briefly outlined in section 1.5.2.2. However, as a consequence, the unit commitment must be optimized for all states of the SDP problem. Depending on the number of considered investment alternatives and the number of stochastic scenarios, this number can be huge.

7.7.4.2 Pure Simulation-Based Models

The electricity price models presented in section can be used for power plant valuation. To determine the profits of new units, assumptions must be made about the amount of produced electricity. A common assumption is that a unit produces when the simulated electricity prices are higher than the marginal costs of the unit.

Deng,2005 [71] researched the option to invest in a natural gas plant based on stochastic natural gas and electricity spot prices through the extension of a model, which was initially based on a spark spread option valuation scheme, in order to take into consideration the price spikes and jumps of the electricity spot prices. He claims that such price jumps and spikes can have a significant impact on investment decisions.

Fleten and Näsäkkälä, 2003[94] used forward prices in order to evaluate the option to invest in a CCGT unit. Optimal investment entry and exit threshold values are determined depending on the level of operational flexibility of the plant. The results of this work indicate that the operational flexibility has a significant impact on the investment thresholds.

7.7.4.3 Models Based on Fundamental Electricity Market Models

In recent years quite a few models where developed as fundamental electricity markets models. The biggest part of these models are based on a combination of the real options approach with a fundamental electricity market model while taking into consideration uncertainties of e.g. fuel prices or carbon prices ,which are limited to a few scenarios only, though .

Further analysis of these models is beyond the scope of this thesis.

7.8 Literature Review on the impact of EU ETS on Investment Decisions

The EU ETS and its influence on corporate decisions so far have been analyzed from different viewpoints. Most of this research does not empirically investigate the actual effects of the EU ETS since its introduction. Instead, the focus is rather on expected effects such as the possible outcomes of different regulatory specifications. This is mainly because the system has only been started recently and corporate reactions are still in the process of being implemented.

In fact literature on power generation investment under uncertainty is growing rapidly. The idea here is not to provide an exhaustive survey, but rather to give a taste of the diversity of studies that have been added to the literature in recent years.

In an empirical report from year 2005 prepared by IPA Energy with the title *'' Implications of the EU Emissions Trading Scheme for the UK Power Generation Sector''*[95], several UK and European power industries cited as the most important factors which affect investment decisions in the power generation industry are the financial fundamentals (e.g., spark spread for CCGT plants and the feed-in tariffs for renewable technology) and the degree of market liberalization. Taxation was a further factor reported , whereas transportation costs of fuel and electricity were mentioned as a less important constraint, which was still important for new built plants. Finally, the EU ETS decisions were seen as important, but relatively less than the aforementioned.

A more recent empirical survey dated December 2009 carried out by New Energy Finance ''*Impacts of the EU ETS on power sector investments –a survey of European utilities*'', 2009 [96] concerning the largest EU power companies, showed that the EU ETS was inhibiting capital investment decisions in the European power industry. The key conclusions from the survey were:

- *''Carbon prices are being fully integrated into investment decisions in the European power sector. All power generators interviewed in the survey calculate a carbon price in their investment decisions with most running several future price scenarios*
- *Although the carbon price (current and projected) is not sufficient to justify an immediate wholesale shift to lower CO_2 emitting technologies it is making power companies alter their investment focus to include more lower carbon technologies, such as CCGT and high efficiency coal, in their future plant mix.*
- *The EU ETS is having a clear impact on:*

    - *The addition of new biomass co-firing capacity*
    - *Early closure of older, dirtier oil, coal and lignite plants, particularly in the Large Combustion Plant Directive*
    - *Investments in CCS although direct government support also plays a role in CCS decisions, the EU ETS is the most important consideration*
- *In most cases the EU ETS is one factor taken into account when making investment decisions in the power sector. Fuel prices, electricity prices and direct government subsidies or targets (for renewables) are equally important.''*

Hoffman, 2007[8] has done an empirical research on the effect of the CO_2 price on investment decisions in the period 2005-2007 by performing interviews with people from five power companies in Germany.

Regarding the effectiveness of the EU ETS, the findings from the case studies for the German electricity industry suggest that the basic principle of the regulation is functioning as CO_2 allowance prices are integrated into corporate decision making. Furthermore Hoffman argues that although the EU ETS presents an important first move towards the mitigation of climate change, the actual technological changes induced by the EU ETS seem to be only moderate. The industry takes limited risk and implements low carbon investments such as short-term investments such as retrofits or investments with an option character such as R&D. However, for large-scale investment decisions which have long amortization time periods, the implementation of the EU ETS during its first phase did not obtain an optimal regulatory environment for low carbon electricity generation.

A set of further studies dealt with the analysis of one of the aims of the EU ETS which is to encourage innovation. Schleich and Betz, 2005[97] contributed an evaluation of the regulatory details of the EU ETS from the point of view of technological innovation incentive . They concluded that there are only mediocre incentives for developing low carbon technologies under the imposed allocation rules for the trial phase between 2005 and 2007 because most of the scheme's design characteristics are not optimally implemented. Oberndorfer and Rennings, 2007[98] compare different theoretical studies to estimate the effects of the EU ETS on competitiveness and came to similar to Schleich and Betz conclusions that the scheme's impact on innovation is rather restricted.

Grubb and Newbery, 2007[99] argue that the CO_2 price risk has the important feature of being mainly a regulatory risk which is definitely hard for private companies to manage . Furthermore, they argue that this risk for fossil fuel plants is limited because they can pass through the risk of CO_2 and fuel price to end consumers due to the fact that fossil fuel plants are usually the marginal plants. They conclude that investors will take the lowest possible risk while investing in a CCGT that is characterized by short lead times and low investment costs.

Research by Jensen & Meibom, 2008[100] focused on the effect of the CO_2 price on investments in gas fired power plants concentrating in the Nordic spot market. They analyzed the possibility and the time frame investors choose to invest in new production capacity depending on their existing portfolio of power producing units. With the assumption of perfect competition an electricity market equilibrium model of the Nordic power system was developed in combination with a real options model concerning investment decisions. Various scenarios were modeled for the development of key parameters such as the CO_2 emission allowance price in order to find out the impacts for investments in a natural gas fired power plant they concluded that new investments are extremely sensitive to the investors existing power production portfolio due to the competition of new production units with the existing power plants.

Roques et al., 2008[101] carried out a portfolio analysis taking into consideration nuclear, gas and coal plant investment options. They concluded that for risk averse companies the most attractive, possible choice is to have a portfolio consisting only of natural gas plants or a portfolio with a high percentage of gas plants. It is important to mention that the authors conclusion is based on the assumption that in liberalized markets the prices of natural gas, CO_2 and electricity are highly correlated with each other. Furthermore if prices showed limited correlationd, the best investment strategy would be more diversification between all three technologies.

Kara et al.,2008[102] investigated policy uncertainty who argue that investors in the Nordic electricity market postpone their investments due to the regulatory uncertainty regarding the EU ETS.

Regarding short term investment planning, the real options approach was preferred and implemented by e.g. Tseng et al., 2002[103] who presented a valuation method for power plants using a Monte Carlo simulation which can additionally be used for long-term valuation purposes and Hlouskova et al., 2005[104] who used complex Monte-Carlo simulations which proved to be especially advantageous in dealing with jumps as the underlying risk factor, showing the best application in peaking units which are characterized by rare and short lived spikes.

At the same time, quite a number of long-term planning methods have been developed. Recent examples include Fleten et al., 2007[105], who argue that power plant investments demand higher returns than the typical net-present-value (NPV) breakeven point while using a real options approach with stochastic prices .

Using ROA, Sekar, 2005[106] evaluated investments in three coal fired generation technologies considering uncertain CO_2 prices: pulverized coal, standard Integrated Gasification Combined Cycle (IGCC), and IGCC with pre investments to reduce the cost of future carbon capture and storage (CCS). His contribution concentrates on the development of the cash flow model for each of the three technologies, with the CO_2 price being an uncertain variable combining market-based valuation to calculate cash flow uncertainty and dynamic quantitative modeling to capture the effect of uncertainty.

Laurikka, 2006[107] presented a simulation model using the real option approach in order to assess the value of the Integrated Gasification Combined Cycle (IGCC) technology operating inside an emissions trading scheme. The model took into consideration three types of stochastic variables which were the price of electricity, fuel an emission allowances. His major conclusion was that the IGCC technology is not competitive within the EU ETS without taking into account of the CO_2 prices.

Further use of real options has taken place in the area of modeling uncertain climate change policy, e.g., Rothwell, 2006[108] used the ROA approach to evaluate risks deriving from the development of new nuclear power plants. His model considered the uncertainties of price, output and cost risk. He concluded that the return on the investment for a nuclear plant needs to be higher in an investment environment with prevailing uncertain carbon prices compared with one in which carbon prices are characterized by certainty.

Laurikka and Koljonen, 2006[109], Kiriyama and Suzuki, 2004[110] deal with the impacts of uncertain future emissions trading and with CO2 penalties within a real options setup. It needs to be mentioned that in these models, the design of emissions trading schemes and the number of allowances that are freely allocated are main characteristics of the overall models.

Blyth et al., 2007[49]) and Yang et al., 2007[68] argue that the climate change policy uncertainty is reflected in the investment decisions through an uncertain carbon price. They have compared a gas, coal and nuclear power plant and they further claimed that decisions under uncertainty should only be taken ‘’*when the costs of waiting exceed the expected value of information available through waiting’’*. Furthermore they argued that ‘’*the value of waiting is more important when a regulatory intervention is closer in time because there is less time left before the intervention’’*. Figure 7.12 shows the risk premiums (i.e. the additional financial returns that would be required to carry out the investment) in terms of additional capital investment costs (USD/kW) that are associated with uncertainties of energy and carbon price.

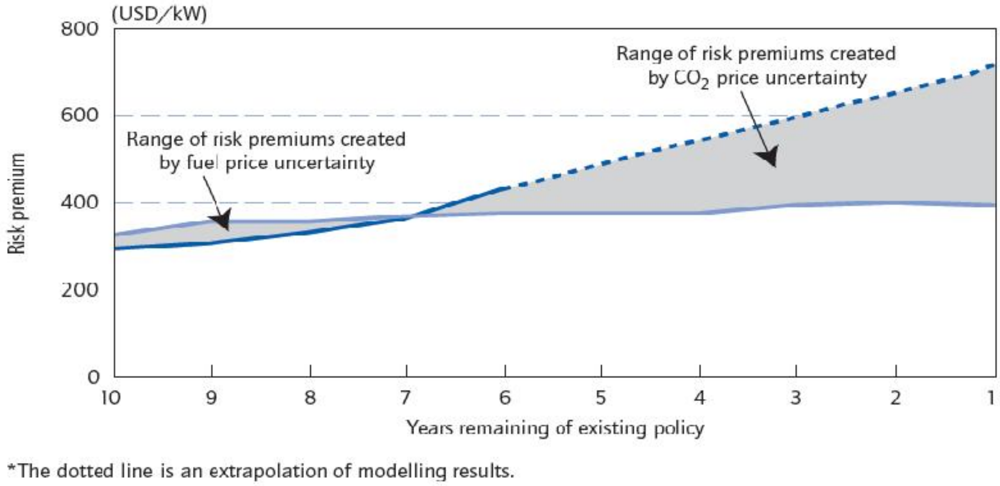

Figure 7.12: Range of risk premiums for new investments created by uncertainty, Blyth et al., 2007[28]).

Blyth, W., 2007 [1] states that the periodic behavior of regulatory interventions , such as are observed in the case of the EU-ETS where new emissions caps are set before the launch of each regular trading period, lead to the periodic behavior of the risk premiums as well (Figure 7.13.) With the date of the policy review getting closer, the risk premium soars because there is not enough time available to achieve a return on investment before a change in the policy conditions. As soon as the new policy environment has been established, the risk premium drops again until the next rise which will take place when the next policy review point will approach. In conclusion, power utilities will have the tendency to show preference in making their investments as far as possible from the next expected policy review, a fact which leads to cyclical investment phases.

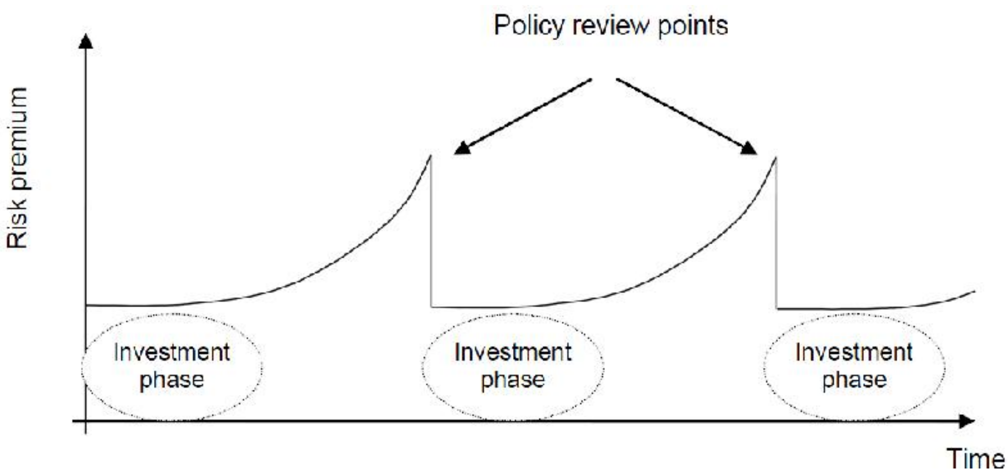

Figure 7.13: Periodic regulatory intervention leads to periodic investment phases., Blyth, 2007[1].

Both reports also state that nuclear plants seem to be more exposed to CO_2 price risk than fossil fuel plants. The CO_2 price also influences the marginal cost of a gas or a coal plant, but does not influence the marginal cost of a nuclear plant, thus the impact of a CO_2 price change is for a nuclear plant definitely larger.

Yang and Blyth, 2007[69] undertook the real option approach with the computer modeling to quantify the impacts of the climate change policy which is looming up as an essential factor in the power sector investment. Different from the previous studies, they formulated multi stage investments taking two stochastic variables into account: prices of electricity and CO_2 allowance.

7.9 Conclusions

In this chapter, we presented methods for assessing investment projects under uncertainty. First, we described briefly which are the actual strategic actions taken by power generators. In the following section, we presented different methods used in decision making on power plant investments: the DCF analysis, the LCOE approach, the screening curve method and the real options approach. The first, the second (which is based on the first) and the third methods are mainly used in regulated market conditions, and are not suited to consider the uncertainties to which generation companies are exposed in a deregulated market.

The real options approach was developed for investments under uncertainty. Besides the question whether to invest or not, the real options approach also addresses the question when to invest based on the assumption that the option to invest has a value. Due to its ability to consider uncertainties in an appropriate way, most investment models used widely today are based on the real options approach.

In the last section of this chapter we briefly described some simulation-based and some game-theoretic approaches to power generation expansion, before we discussed the optimization based power generation expansion models.

Next we presented a literature review on the impact of the EU ETS on power plant investment decisions.

The first conclusion drawn from the literature review on the impact of EU ETS on investment decisions is, according to an empirical survey by New Energy Finance, 2008 , the fact that the EU ETS is indeed starting to change the European power industry's capital investment decisions.

The same conclusion is delivered by a further empirical study by Hoffman, 2007 who argues that CO_2 allowance prices are integrated into several aspects of corporate decision making although actual technological changes induced by the EU ETS seem to be moderate and mostly concentrated on low carbon investments with limited risks such as short-term investments or investments with an inherent option character (R&D), whereas for large-scale, low carbon investments, regulatory and price uncertainties reduced the incentives. Concerning the impact of EU ETS on technological innovation incentives for the EU ETS pilot phase 2005-07, two studies -Schleich and Betz, 2005 and Oberndorfer and Rennings, 2007- both conclude that the scheme's impact on innovation investments has been rather small.

Furthermore it is evident from the literature review that there is no agreement among contributors on what is the best investment strategy concerning CO_2 price uncertainty. Some argue that a pure portfolio of gas plants is the best because when the CO_2 price increases the electricity price increases as well adding to the fact that gas plants have a short lead time and low investment cost (Grubb and Newbery, 2007, Roques et al., 2008).

According to Hoffman, different companies come to different conclusions about what is the best investment strategy based on the assumptions they use in their investment analysis.

A lot of authors agree that the option to wait with the investment decisions can have a certain value (Yang et al., 2007, Jensen and Meibom, 2008, Blyth at al, 2007[67]). Others have already observed the behavior that power companies seem to delay their investment decisions (Kara et al., 2008, Hoffman, 2007).

The characteristics of power plant investment decisions makes it particularly relevant to use the ROA. The ROA has been applied e.g. to valuations of a peak-load power plant (Hlouskova et al., 2005), gas fired power plants (Jensen & Meibom, 2008) pulverized coal and Integrated Gasification Combined Cycle (IGCC) plants, Sekar, 2005; Laurikka, 2006),of regulatory risks in the development of new nuclear power plants Rothwell, 2006 etc.

Concerning short-term investment planning, real options were used by Tseng e.al, 2002 who presented a method for valuing a power plant which can also be used to aid long-term valuation, Hlouskova et al.,2005 who developed a method which prove to be especially advantageous when price jumps and spikes occur applying best in peaking units while Fleten et al., 2007, contributed in a long-term planning approach.

The impact of regulatory uncertainty on investment decisions has been modeled with ROA by many studies (Blyth et al., 2007; Yang et al., 2007 ; Kara et al.,2008 Brunekreeft and Mc Daniel, 2005; Rothwell, 2006; Laurikka and Koljonen, 2006; Kiriyama and Suzuki, 2004).

In summary, as the regulation has only been implemented recently, the literature seems to be missing empirical evidence regarding the actual effects that the EU ETS has on power generation firms although the price signal affects their investment decisions.

CHAPTER 8

CONCLUSIONS

Power plant investments are uncommon for financial and technical reasons, with large capital outflows which demand reliable valuation and decision-making tools. In addition, power plant investments are characterized by a certain form of irreversibility and the option to postpone which expose investors to several long run uncertainties with the most important being long-term electricity and fuel prices.

The process of investment decision-making for European power utilities became more complex with the implementation of the European Union Emission Trading Scheme (EU ETS) in 2005, because it introduced a highly uncertain and volatile price on carbon emissions, as a possible way to create incentives for companies to adjust their behavior and invest in lower-emitting technologies. Furthermore, the electricity market liberalization has progressed, introducing uncertain customer demand as well as uncertain power prices which have made the investment decision-making procedure even more difficult.

We have documented in chapter 5 of this work that the EU ETS affects the operations and the profitability of power generators. The impact of the EU ETS is felt indeed in many different parts of the business although the existence of a carbon price does not guarantee that abatement will take place. Actually there are other factors in the market which will change the ultimate impact of emissions trading. E.g., the merit order and the aspects influencing its structure provide a better tool for looking at the dynamics of power plant portfolios.

Taking into consideration the risks to which power plant profitability is exposed which are fuel, carbon, and electricity price risks as well as risks about the legal framework, we have presented in chapter 6 different approaches to forecast through modeling fuel, carbon and electricity prices. We concluded that there is a wide variety of different stochastic processes used for the simulation of these highly interdependent prices, but there is actually no consensus in literature which approach is the appropriate one.

The critical discussion in chapter 7 of the classical valuation methods used in decision making on power plant investments such as the DCF analysis, the LCOE approach and the screening curve method showed that these are insufficient considering uncertainties. In an effort to overcome these limitations, the real options approach evolved recently allowing decision makers to incorporate uncertainty in their investment decisions by giving them the option to postpone the initial investment undertaken, which gives them flexibility in the investment timing, the option to alter operation scale (expand or contract),the option to abandon (temporarily or definitively) and the option to switch (from one operating process to another) . Studies have shown that the ROA has been successfully applied e.g. to valuations of a peak-load power plant , gas fired power plants , pulverized coal and Integrated Gasification Combined Cycle (IGCC) plants.

Furthermore, the shift towards more liberalized markets triggered interest in developing electricity market models which are very capable software tools modeling various portfolios and multiple scenarios with the interest concentrating on optimization models, equilibrium models and simulation models.

Because the regulation has only been implemented recently, there is not enough empirical evidence regarding the actual effects that EU ETS and consequently the carbon price have on power generation firms although the price signal affecting their investment decisions has been confirmed.

Empirical studies have shown that carbon prices influence the European power industry's capital investment decisions with technological changes induced by the EU ETS, while at the same time being rather week and mostly concentrated on low carbon investments of limited risks such as short-term investments or investments in R&D, whereas for large-scale, low carbon investments, regulatory and price uncertainties reduce the incentives. Moreover, studies have shown that for the EU ETS pilot phase 2005-07, the scheme's impact on innovation investments has been rather small.

Unfortunately there is no agreement in bibliography on what is the best investment strategy concerning CO_2 price uncertainty. E.g. some contributors argue that a pure portfolio of gas plants is the best possible, while others suggest that the CO_2 price uncertainty will be an incentive to further diversification.

Furthermore, a lot of authors agree to a general rule that investment decisions under uncertainty should only be taken when the costs of waiting exceed the expected value of information available through waiting, while others have already observed the behavior that power companies seem to delay their investment decisions due to the carbon price.

The fact that the climate change policy uncertainty is represented in the investment decision by means of an uncertain carbon price, might lead to thoughts of implementing, alternatively to the cap-and-trade scheme, of other carbon policies. E.g. through imposing a sufficiently high carbon tax, carbon market price volatility would extinguish and investments in low emission technologies could be stimulated. In report [21], the clear advantages of a carbon tax were modeled and documented while stating that a carbon tax results in lower electricity prices and , in contrary to emissions trading, to a complete phase out of conventional coal power plants.

Reconsideration of current carbon policies by policy makers and a switch to an alternative (for e.g. like in United Kingdom with the recent introduction of a hybrid carbon policy), might be the secret in achieving long-term visibility and the diminish of market volatility of the European carbon price which in turn would assist European utilities decision makers in optimizing their power plant investments in the best possible way.

Finally, policy makers should bear in mind that the abandonment of the EU ETS must be considered as a realistic future option in the very probable case that no post–Kyoto international agreement will be agreed, otherwise big troubles are ahead for the European power generation industry.

REFERENCES

[1] Blyth, W., 2007. Incentives, risk and decision making in mitigating climate change. The Chatham House.

[2] IEA, 2009a. Detailed description of the world energy model. http://www.worldenergyoutlook.org/docs/weo2009/World Energy Model.pdf.

[3] IEA,2010. Projected costs of generating electricity, Technical report, International Energy Agency, World Energy Outlook .

[4] Birol, F. 2003: World Energy Outlook 2020 and Global Electricity Investment Challenges. Presentation at the conference: Power Generation Investment in Liberalised Electricity Markets, organized by the Nuclear Energy Agency, March 25 – 26, 2003. Paris.

[5] RWE ,2011

[6] McKinsey & Company ,2009. Pathways to a low-carbon economy: version 2 of the global greenhouse gas abatement cost curve, Technical report, McKinsey and Company.

[7] Stern, N. 2007. The Economics of Climate Change: The Stern Review, Cambridge University Press.

[8] Hoffmann, V. H. (2007). EU ETS and investment decisions : The case of the german electricity industry, European Management Journal 25(6): 464 - 474. Business, Climate Change and Emissions Trading.

[9] IEA, 2003. Risks Facing Energy sector investments . World Energy Investment Outlook .

[10] Lemming, J., 2005. Risk and investment management in liberalized electricity market. PhD thesis. Department of Mathematical Modelling, Technical University of Denmark.

[11] Roques, F.A., Newbery, D.M., Nuttall, W.J. 2006 Using Probabilistic Analysis to Value Power Generation Investments Under Uncertainty .

[12] Nuclear energy agency ,OECD 2011. Carbon pricing, power markets and the

competitiveness of nuclear power, executive summary.

[13] EON, 2011. EON 's Interim Report II/2011

[14] Weber, C. and Swider, D.J.,2004. Power Plant Investments under fuel and carbon Uncertainty. Presented at the 6th IAEE European Conference 2004 on Modeling in Energy Economics and Policy.

[15] Haas, R.,Redl, H., Auer, H.,2009. The Changing Structure of the Electric Utility Industry in Europe: Liberalization, New Demands and Remaining Barriers Handbook Utility Management.

[16] Gross, R., Heptonstall, P. and Blyth, W., 2007. Investment in Electricity generation: the role of costs, incentives and risks, Imperial College Centre for Energy Policy and Technology.

[17] Aıd,R. , 2011. Investment Decision in Power Markets ,Lecture 1 — Context & Problem Description, Wolfgang Pauli Institute – Vienna.

[18] International Energy Agency, 2003, *Power Generation Investment in Electricity Markets.*

[19] Stavins, R. N. 2002. Economic incentives for environmental regulation, Technical Report Harvard University. Discussion Paper E-97-02,.

[20] Hardin, G., 1968. The Tragedy of the Commons, Science, 162(1968):1243-1248.

[21] Chappin, E., Dijkema, G. and Vries, L.d., 2010, Carbon policies: Do they deliver in the long run? Textbook Sioshansi, F. Generating electricity in a carbon constrained world.

[22] PriceWaterhouseCoopers, 2009. Carbon Taxes and Trading Pros, cons and the case for a hybrid approach.

[23] Wood, P.J. and Jotzo, F., 2010. Price Floors for Emissions Trading.

[24] Tietenberg, T. H., 2006. Emissions trading: principles and practice, 2nd edn, Resources for the Future, Washington, DC.

[25] Chlistalla, M , Zähres, M , 2011 Bidding for the better The EU ETS moves to auctioning, Deutsche Bank Research.

[26] De Bruyn, S.M., 2010. Emission Trading In Practice (CE Delft)

[27] Sijm, J., Neuho, K. and Chen, Y., 2006 .Cost pass-through and windfall profits in The power sector, Climate Policy 6(1): 49-72.

[28] Blyth, W., Yang, M. and Bradley, R. 2007. Climate Policy Uncertainty and

Investment Risk, OECD/IEA.ISBN: 978-92-64-03014-5 – 2007

[29] European Commision Climate Action, 2010. http://ec.europa.eu/environment/climat/emission/citl_en_phase_ii.htm

[30] Kossoy A. Ambrosi P., State and Trends of the Carbon Market 2010, World Bank.

[31] Tvinnereim, E., Røine, K. and Heimdal, C. Point Carbon (2009): ”Carbon 2009 - Emission trading coming home.

[32] Chevallier, J., 2011. Carbon Price Drivers: An Updated Literature Review

[33] Ellerman, A.D., & Buchner, B.K. 2007. The European Union Emissions Trading Scheme: Origins, Allocation, and Early Results. *Review of Environmental Economics and Policy* 1(1), 66-87.

[34] Christiansen, A.C., Arvanitakis, A., Tangen, K., & Hasselknippe, H., 2005. Price Determinants in the EU emissions trading scheme. *Climate Policy* 5, 15-30.

[35] Mansanet-Bataller, M., Pardo, A., & Valor, E., 2007. CO2 Prices, Energy and Weather. The Energy Journal 28, 73-92.

[36] Alberola, E., Chevallier, J., & Chèze, B. 2008a. Price Drivers and Structural Breaks in European Carbon Prices 2005-07. *Energy Policy* 36(2), 787-797.

[37] Delarue, E.D., & D’haeseleer, W.D., 2007. Price determination of ETS allowances through the switching level of coal and gas in the power sector. *International* Journal of Energy Research 31, 1001-1015.

[38] Alberola, E., Chevallier, J., & Chèze, B. (2008a). Price Drivers and Structural Breaks in European Carbon Prices 2005-07. *Energy Policy* 36(2), 787-797.

[39] Keppler, J.H., & Mansanet-Bataller, M. (2010). Causalities between CO2, electricity, and other energy variables during phase I and phase II of the EU ETS. *Energy Policy* 38(7), 3329-3341.

[40] Alberola, E., Chevallier, J., & Chèze, B., 2008b. The EU Emissions Trading Scheme: the Effects of Industrial Production and CO2 Emissions on European Carbon Prices. International Economics 116, 93-126.

[41] Declercq, B., Delarue, E., & D’haeseleer, W., 2011. Impact of the economic recession on the European power sector’s CO2 emissions. *Energy Policy* 39, 1677-1686.

[42] Oberndorfer, U., 2009. EU Emission Allowances and the stock market :

Evidence from the electricity industry. *Ecological Economics* 68, 1116-1126.

[43] Wagner, R., 2009. The impact of the EU Emissions Trading Scheme on power – The price to be paid for CO2 abatement? , Paper for the NARUC/NCEP Climate Change Conference Dallas, Texas.

[44] PriceWaterhouseCoopers, 2005. Responding to a changing environment :Applying emissions trading strategy to industrial companies.

[45] Günther, B. and Alphéus, I., 2010. RWE Supply & Trading GmbH | Commerzbank German Investment Seminar 2010.

[46] Carmona, R., Emissions Markets I Cap and Trade schemes: First equilibrium Methods ORFE, Bendheim Center for Finance Princeton University, 2011.

[47] Bausch, A., and Schwenker, B., Handbook Utility Management, Springer Verlag 2009

[48] Garz, H., WestLB. Deutsche Versorger in der CO_2-Falle, 2009

[49] Sijm, J., 2007. The impact of the EU ETS on electricity prices Workshop "Ex-post analysis of the EU Emissions Trading Scheme", University of Vigo, November 16, 2007.

[50] Sijm, J.P.M.,Hers S.J., Lise W. and Wetzelaer, B.J.H.W, 2008. The impact of the EU ETS on electricity prices. Final report to DG Environment of the European Commission

[51] VIK, 2006. Opinion on the preliminary findings of the electricity sector inquiry, Technical report, VIK, Essen. http://www.vik.de/fileadmin/vik/Stellungnahmen/2006-04 21/SN_preliminary_findings_sector_inquiry.pdf)

[52] Reinaud, J. 2007, CO2 allowance and electricity price interaction: impact on industry's electricity purchasing strategies in Europe.

[53] PointCarbon, 2008b. EU ETS Phase II -The potential and scale of windfall profits In the power sector.

[54] Ellerman, A. D. and Joskow, P. L. (2008). The European Union's Emissions Trading System in Perspective, Pew Center on Global Climate Change.

[55] New Carbon Finance,2008. The impact of auctioning on European wholesale electricity prices post-2012.

[56] Røine, K., E. Tvinnereim, H. Hasselknippe, Point Carbon, 2008a. Carbon 2008 -

Post-2012 is now"
[http://www.pointcarbon.com/research/carbonmarketresearch/monitor/1.263081].

[57] Sijm, J.P.M, Bakker, S.J.A, Chen,Y., Harmsen, H.W. and Lise, W, 2005. CO2 pricedynamics: The implications of EU emissions trading for the price of electricity. Energy research Centre of the Netherlands (ECN).

[58] Obermayer, J., 2010. An analysis of the fundamental price drivers of EU ETS carbon credits, Department of Mathematics, Royal Institute of Technology (KTH), Stockholm.

[59] Delarue, E., Voorspools, K., D'haeseleer, D., 2008. Fuel switching in the electricity sector under the EU ETS: review and prospective. TME Working Paper - Energy and Environment, KU Leuven Energy Institute.

[60] Botterud A., Ilic M. and Wangensteen I., 2005. Optimal investments in power generation under centralized and decentralized decision making". In: Power Systems, IEEE Transactions on 20.1 (2005), pp. 254–263.

[61] Manera, M., Longo C., Markandya, A. and Scarpa E., 2007 Evaluating the Empirical Performance of Alternative Econometric Models for Oil Price Forecasting. Fondazione Eni Enrico Mattei Working Paper 69.

[62] Engdahl F.W., 2008 http://www.globalresearch.ca/index.php?aid=8878&context=va

[63] Paolella, M.S., & Taschini, L., 2008 . An econometric analysis of emission allowance prices. Journal of Banking and Finance 32(10), 2022-2032.

[64] Benz, E. and Trück, S, 2009. Modeling the price dynamics of CO2 emission allowance. In: Energy Economics 31.1 (2009), pp. 4–15.

[65] Dannenberg, H. and Ehrenfeld ,W., 2008. Prognose des CO2-Zertifikatepreisrisikos, IWH-Diskussionspapiere 5. Halle Institute for Economic Research.

[66] Daskalakis, G., Psychoyios, D., & Markellos, R.N. 2009. Modeling CO2 emission allowance prices and derivatives : Evidence from the European trading scheme. Journal of Banking and Finance 33(7), 1230-1241

[67] Blyth, W., Bradley, R., Bunn, D., Clarke, C., Wilson, T., Yang, M. 2007 Investment risk under uncertain climate change policy, Energy policy 35, 5766-5773.

[68] Yang, M., Blyth, W., Bradley, R., Bunn, D., Clarke, C., & Wilson, T. 2007. Evaluating the power investment options with uncertainty in climate policy. Energy Economics, 30(4), 1933-1950.)

[69] Yang, M., Blyth, W., 2007. Modeling investment risks and uncertainties with real options approach. International Energy Agency Working Paper Series LTO/2007/WP 01, Paris.

[70] Sun, N., Ellersdorfer, I., and Swider, D.J., 2008. Model-based long-term electricity generation system planning under uncertainty In: *2008 Third International Conference on Electric Utility Deregulation and Restructuring and Power Technologies*. Nanjing, China, pp. 1298–1304.

[71] Deng,S.J., 2005. Valuation of investment and opportunity-to-invest in power generation assets with spikes in electricity prices . In: Managerial Finance 31, pp. 95–115.

[72] Burger, M., Klar, B., Müller, A., and Schindlmayr G. A spot market model for pricing derivatives in electricity market. In: Quantitative Finance 4 (Feb. 2004), pp. 109–122.

[73] Geman, H. and Roncoroni, A., 2006. Understanding the Fine Structure of Electricity Price. In: The Journal of Business 79.3 ,pp. 1225-1261.

[74] Damodaran, A. 2011. *Applied Corporate Finance* ISBN 978-0-470-38464-0.

[75] Royal Academy of Engineering , 2004. The cost of generating electricity :A commentary on a study carried out by PB Power for The Royal Academy of Engineering.

[76] Khatib, H.2003. Economic evaluation of projects in the electricity supply industry, The Institution of Engineering and Technology. ISBN 0-86341-304-8.

[77] IEA ,2010, WORLD ENERGY OUTLOOK , EXECUTIVE SUMMARY.

[78] Bhattacharyya, S.C. 2011, Energy Economics, Concepts, Issues, Markets and Governance, ISBN 978-0-85729-267-4 Springer-Verlag.

[79] Arthur D.Little, 2008 .Real Options for the Future Energy Mix .

[80] Sapienza, M.D. and Stefanoni, *S*., 2007. EU Emissions Trading Scheme and Investments in the power sector 2007.

[81] Ventosa, M., Denis, R. and Redondo, C. Expansion Planning in Electricity Markets. Two Different Approaches.

[82] International Atomic Energy Agency,1984. Expansion Planning for Electrical Generating Systems : A Guidebook, Technical Reports Series No 241, ch. 7.

[83] Foley, A.M., Ó Gallachóir, B.P., Hur,J., Baldick, R., E.J. McKeogh, E.J., 2010 A strategic review of electricity systems models, Energy, 35 :4522-4530.

[84] Argyris, G. , Kagiannas, A.G., Dimitris, Th., Askounis, D.Th. and Psarras, J.,2004, Power generation planning: a survey from monopoly to competition. In: International Journal of Electrical Power & Energy Systems 26, pp. 413–421.

[85] Assili, M., Javidi, M. and Ghazi, H., 2008. An improved mechanism for capacity payment based on system dynamics modeling for investment planning in competitive electricity environment. Energy Policy 36, 3703-3713.

[86] Bunn, D.W. and Larsen, E.R.,1992 Sensitivity of reserve margin to factors influencing investment behavior in the electricity market of England and Wales. In: Energy Policy 20.5 , pp. 420–429.

[87] Vogstad, K.O., 2004. A system dynamics analysis of the Nordic electricity market: The transition from fossil fuelled toward a renewable supply within a liberalised electricity marke . Doctoral thesis Faculty of Information Technology, Mathematics and Electrical Engineering Norwegian University of Science and Technology (NTNU).

[88] Olsina, F. Long-Term Dynamics of Liberalized Electricity Market, PhD thesis. Instituto de Energía Eléctrica, UniversidadNacional de San Juan, Sept. 2005.

[89] Sensfuß, F., Ragwitz, M., Genoese, M. and Möst ,2007.M. Agent-based Simulation of Electricity Markets – A Literature Revie. In: Energy Studies Review 15.2 , pp. 19–47.

[90] Czernohous, C., Fichtner, W., Veit, D.J , and Weinhardt, C.2003 Management decision support using long-term market simulation . In: Information Systems and E-Business Management 1.4 pp. 405–423.

[91] Genoese, M., Sensfuß, F., Möst, D., and Rentz ,O. Agent-Based Analysis of the Impact of CO2 Emission Trading on Spot Market Prices for Electricity in German. In: Pacific Journal of Operations Research 3.3 (2007), 401˝U –423.

[92] Chuang, A.S., Wu, F., and Varaiya, P.,2001. A game-theoretic model for generation expansion planning: problem formulation and numerical comparisons”. In: Power Systems, IEEE Transactions on 16.4 , pp. 885–891.

[93] Murphy, F.H. and Smeers, Y.,2005. Generation Capacity Expansion in Imperfectly Competitive Restructured Electricity Market. In: Operations Research 53.4 , pp. 646–661.

[94] Fleten S-E. and Erkka Näsäkkälä E., 2003. Gas fired power plants: Investment timing, operating flexibility and CO2 capture. MPRA Paper 15716.

[95] IPA Energy, 2003. Implications of the EU Emissions Trading Scheme for the UK Power Generation Sector.

[96] New Energy Finance, 2009 Impacts of the EU ETS on power sector investments –a survey of European utilities .

[97] Schleich, J. & Betz, R. 2005. Incentives for energy efficiency and innovation in the European Emission Trading System. ECEE

[98] Oberndorfer, U. and Rennings, K. 2007. Costs and competitiveness effects of the European Union emissions trading scheme. European Environment 17(1), 1–17.

[99] Grubb, M., Newbery, D, 2007. Pricing carbon for electricity generation: National and International dimension. Faculty of economics, Cambridge.

[100] Jensen, S.G., Meibom, P., 2008. Investments in liberalised power markets Gas turbine investment opportunities in the Nordic power system , Electrical power and energy systems 30 113-124.

[101] Roques, F.A., Newbery, D.M., Nuttall, W.J., 2008. Fuel mix diversification incentives in liberalized electricity markets: A mean variance portfolio theory approach, energy economics 30, 1831-1849.

[102] Kara, M., Syri, S., Lehtila, A., Helynen, S., Kekkonen, V., Ruska, M., Forsstrom, J., 2008. The impacts of EU CO2 emissions trading on electricity markets and electricity customers in Finland , Energy economics 30. 193-211.

[103] Tseng, C., Barz, G., 2002. Short-term generation asset valuation: a real options approach. Operations Research 50 (2), 297–310.

[104] Hlouskova, J., Kossmeier, S., Obersteiner, M., Schnabl, A., 2005. Real options and the value of generation capacity in the German electricity market. Review of Financial Economics 14 (3–4), 297–310.

[105] Fleten, S., Maribu, K., Wangensteen, I., 2007. Optimal investment strategies in decentralized renewable power generation under uncertainty. Energy 32 (5), 803–815.

[106] Sekar C. 2005. Carbon Dioxide Capture from Coal-Fired Power Plants: A Real Options Analysis, Massachusetts Institute of Technology, Laboratory for Energy and the Environment, 77 Massachusetts Avenue, Cambridge, MA 02139-4307, US.

[107] Laurikka, H., 2006. Option Value of Gasification Technology within an Emissions Trading Scheme. Energy Policy, 34, Issue 18, pp 3916-3928.

[108] Rothwell, G. 2006 A Real Options Approach to Evaluating New Nuclear Power Plants. The Energy Journal; Vol 27, No1 pp 37-53.

[109] Laurikka H. and Koljonen , T., 2006. Emissions trading and investment decisions in the power sector – a case study in Finland. Energy Policy 34(9), 1063–1074.

[110] Kiriyama, E., Suzuki, A., 2004. Use of real options in nuclear power plant valuation in the presence of uncertainty with CO2 emission credit. Journal of Nuclear Science and Technology 41 (7), 756–764.